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Development Document for Proposed Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category

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Proposed

Offshore Segment of the Oil and Gas Extraction

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DEVELOPMENT DOCUMENT for PROPOSED EFFLUENT LIMITATIONS GUIDELINES and NEW SOURCE PERFORMANCE STANDARDS for the OFFSHORE SUBCATEGORY of the OIL AND GAS EXTRACTION POINT SOURCE CATEGORY

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I. EXECUTIVE SUMMARY

PROGRAM SUMMARY

This development document presents the technical data base developed by EPA to support proposed effluent limitations guidelines and standards for the Offshore Subcategory of the Oil and Gas Extraction Point Source Category. Technologies covered by this document to achieve these limitations and standards are defined as best available technology economically achievable (BAT) and best conventional pollutant control technology (BCT) for existing sources, and best available demonstrated technology (BADT) for new sources. Best practicable control technology currently available (BPT) effluent limitation guidelines for this industry segment were promulgated on April 13, 1979 (44 FR 22069). BPT guidelines are addressed in this document only to the extent that they serve as a baseline for the development of BAT and BCT effluent limitations guidelines and new source performance standards (NSPS). The basis for BPT can be found in an earlier development document (EPA 440/76-005-a). This document outlines the technology options considered and the rationale for selection of the technology levels on which effluent limitations and standards are based.

CONCLUSIONS

Information was gathered for this program from various sources including EPA in-house data, EPA contractor data, other Federal and state government agencies, technical publications, contacts with industry representatives, trade associations, and equipment manufacturers. A description of the industry was prepared together with an in-depth study of the characteristics of the waste streams generated by this point source category. Based on an analysis of these data, pollutant parameters were selected and various technologies for eliminating or reducing the discharge of these pollutants to waters of the United States were studied. In addition, cost estimates were prepared on the implementation of the various treatment technology options based on 32 model platforms in various geographical locations in the U.S. The treatment technology and control cost estimates were then used to conduct an economic impact analysis on this industrial point source category.

PROPOSED REGULATIONS

New Source Performance Standards (NSPS)

Produced Water. EPA is proposing performance standards for new source offshore production facilities based upon location and water depth at the facility or at its point of discharge. Zero discharge of produced water would be required for all oil production facilities located in or discharging to 20 meters of water or less in the Gulf of Mexico, the Atlantic Coast and the Alaskan Norton Basin; 50 meters of water or less for the California Coast, the Alaskan Cook Inlet/Shelikof Strait, Bristol Bay and Gulf of Alaska; and 10 meters of water or less in the Alaskan Beaufort Sea.

However, compliance with a zero discharge for these facilities may be delayed for a period of up to 300 days from commencement of development drilling to allow possible cost savings that would be associated with the use of any dry wells drilled that could be equipped and used for produced water reinjection. During the 300 day initial period, standards based upon improved BPT treatment would be required. The standard reflecting improved BPT treatment is 59 mg/l oil and grease as a maximum (no single sample to exceed) value.

For all offshore oil facilities that are not located in or discharged to these shallow water areas and for all gas facilities regardless of location or water depth and for all exploratory facilities, EPA has selected improved BPT treatment which requires a 59 mg/l maximum (no single sample to exceed) standard for oil and grease.

The annualized cost of these proposed standards is estimated to be $55.6 million in the year 2000 (1983 dollars) for the estimated 126 new source production facilities expected to be built between 1986 and the year 2000 which would be subject to this zero discharge standard.

Drilling Fluids. EPA is proposing new source performance standards for drilling fluids. The proposed standards include:

- A prohibition on the discharge of free oil, oil-based drilling fluids, and diesel oil, all considered as "indicators" of toxic pollutants, including benzene, toluene, ethylbenzene, naphthalene, and phenanthrene.

- A 96-hour LC-50 toxicity limitation on the discharged drilling fluids of no less than 3.0 percent by volume of the diluted suspended particulate phase, as defined in the proposed Drilling Fluids Toxicity Test presented in Appendix C.

- A maximum limitation (i.e:, no single sample to exceed) on the amount of cadmium and mercury in discharged drilling fluids of 1 mg/kg dry weight each.

The prohibitions on the discharge of free oil, oil-based drilling fluids, and diesel oil are all intended to limit the oil content in drilling fluid waste streams and thereby control the discharge of toxic, as well as, conventional and nonconventional pollutants present in those oils.

The LC-50 toxicity limitation on the discharge of drilling fluids is intended as an additional control to reduce the toxic constituents in drilling fluid discharges.

The limitations on cadmium and mercury for discharged drilling fluids are intended to control the concentrations of toxic metals in barite, a major component of drilling fluids.

In addition, the Agency is proposing a different definition of the term "no discharge of free oil" from that promulgated for the BPT regulation (44 FR 22075, April 13, 1979). Also, a test procedure for determining compliance with this prohibition on free oil discharges is being proposed in conjunction with the BAT and BCT limitations and NSPS. This test procedure is called the "static sheen test."

This NSPS option is the same as the proposed BAT option for drilling fluids, as discussed below. Therefore, there are no NSPS compliance costs or impacts incremental to BAT for drilling fluids.

Drill Cuttings. The Agency has selected new source performance standards for drill cuttings that would prohibit the discharge of free oil, drill cuttings associated with oil-based drilling fluids, and diesel oil. Such prohibitions are intended to limit the oil content of cuttings waste streams, controlling the discharge of conventional, nonconventional, and toxic pollutants.

Deck Drainage. The Agency is proposing to establish NSPS for deck drainage the same as the BPT level of control. This would result in a prohibition on the discharge of free oil. The Agency is reserving coverage for all other pollutant parameters and characteristics for deck drainage pending additional data collection and analysis.

The method of determining compliance with the free oil prohibition is by the static sheen test. Where deck drainage is collected and treated separately from produced water, the free oil prohibition would apply. However, where deck drainage is commingled and cotreated with produced water, only the standards for produced water would apply to these two combined waste streams.

Because this proposed standard is equal to BAT/BCT, there are no incremental compliance costs due to NSPS.

Sanitary Wastes. The Agency is proposing NSPS for sanitary wastes equal to the BAT/BCT level of control. This would result in: (1) a prohibition on the discharge of floating solids for facilities manned by nine or fewer persons or intermittently manned by any number of persons; and (2) an effluent standard for residual chlorine of 1 mg/l minimum and to be maintained as close to that concentration as possible, for facilities continuously manned by ten or more persons. Because these proposed standards are equal to BAT/BCT, there are no incremental compliance costs due to NSPS.

Domestic Wastes. The Agency is proposing to establish NSPS equal to the BCT level of control for domestic wastes. This would result in a prohibition on the discharge of floating solids. Since NSPS would equal BCT, no compliance costs incremental to BCT are associated with this standard.

Produced Sand. The Agency is proposing an NSPS prohibition on the discharge of free oil from produced sand as an "indicator" to reduce or eliminate the discharge of toxic pollutants in the free oil to surface waters. Coverage of all other pollutant parameters is being reserved pending additional data collection and evaluation. The method of determining compliance with the free oil prohibition is by the static sheen test. There are no NSPS compliance costs incremental to the proposed BAT limitation.

Well Treatment Fluids. The Agency is proposing an NSPS prohibition on the discharge of free oil for well treatment fluids as an "indicator" to reduce or eliminate the discharge of toxic pollutants in the free oil to surface waters. The method of determining compliance with the free oil prohibition is by the static sheen test. This is equal to the proposed BAT level of control, as discussed below. Therefore, there are no compliance costs incremental to BAT.

The Agency is reserving NSPS coverage for well treatment fluids for all other pollutant parameters and characteristics pending additional data collection and evaluation.

Tables I-1 and I-2 summarize effluent limitations for NSPS. "Shallow-water" refers to all offshore oil development and production facilities located in or discharging to water depths of 20 meters or less in the Gulf of Mexico, Atlantic Coast, and

Table I-1

NSPS Effluent Limitations (Shallow-water)

Waste Source	Pollutant Parameter or Characteristic	NSPS Effluent Limitations
Produced water		No discharge[1]
Deck drainage	Free oil [All other pollutant parameters reserved]	No discharge
Drilling fluids	Free oil	No discharge
	Oil-based fluid	No discharge
	Diesel oil	No discharge in detectable amounts
	Toxicity	Minimum 96-hr LC-50 of the diluted suspended particulate phase (SPP) of the drilling fluid shall be 3.0 percent by volume
	Cadmium	1 mg/kg dry weight maximum in the whole drilling fluid
	Mercury	1 mg/kg dry weight maximum in the whole drilling fluid
Drill cuttings	Free oil	No discharge
	Oil-based fluid	No discharge
	Diesel oil	No discharge in detectable amounts
Sanitary M10	Residual chlorine	Minimum of 1 mg/l and maintained as close to this concentration as possible
Sanitary M9IM	Floating solids	No discharge
Domestic waste	Floating solids	No discharge
Produced sand	Free oil [All other pollutant parameters reserved]	No discharge
Well Treatment fluids	Free oil [All other pollutant parameters reserved]	No discharge

[1] Facilities must be in compliance with the no discharge standard no later than 300 days after commencement of development drilling operations. Prior to that date, discharges shall comply with the oil and grease standard of 59 mg/l maximum in S435.15(b).

Table I-2

NSPS Effluent Limitations (Deep-water)

Waste Source	Pollutant Parameter or Characteristic	NSPS Effluent Limitations
Produced water.	Oil and grease	59 mg/l maximum
Deck drainage	Free oil [All other pollutants - Reserved]	No discharge
Drilling fluids	Free oil	No discharge
	Oil-based fluid	No discharge
	Diesel oil	No discharge in detectable amounts
	Toxicity	Minimum 96-hr LC-50 of the diluted suspended particulate phase (SPP) of the drilling fluid shall be 3.0 percent by volume
	Cadmium	1 mg/kg dry weight maximum in the whole drilling fluid
	Mercury	1 mg/kg dry weight maximum in the whole drilling fluid
Drill cuttings	Free oil	No discharge
	Oil-based fluid	No discharge
	Diesel oil	No discharge in detectable amounts
Sanitary M10	Residual chlorine	Minimum of 1 mg/l and maintained as close to this concentration as possible
Sanitary M9IM	Floating solids	No discharge
Domestic waste	Floating solids	No discharge
Produced sand	Free oil [All other pollutant parameters reserved]	No discharge
Well Treatment fluids	Free oil [All other pollutant parameters reserved]	No discharge

Norton Basin; water depths of 50 meters or less in the California Coast, Cook Inlet/Shelikof Strait, the Aleutian Island Chain including Bristol Bay and the Gulf of Alaska; and water depths of 10 meters or less in the Beaufort Sea as specified in Section IX of this document.

"Deep-water" (Table I-2) refers to all offshore exploratory facilities, all offshore gas development and production facilities, and all offshore oil development and production facilities located in or discharging to water depths of more than 20 meters in the Gulf of Mexico, Atlantic Coast and Norton Basin; water depths of more than 50 meters in the California Coast, Cook Inlet/Shelikof Strait, the Aleutian Island Chain including Bristol Bay and the Gulf of Alaska; and water depths of more than 10 meters in the Beaufort Sea as specified in Section IX of this document.

Best Available Technology (BAT)

Produced Water. The Agency is reserving coverage of produced water for existing sources at this time. This is because the Agency lacks sufficient information to properly evaluate the technological feasibility and economic achievability of a reinjection requirement for existing sources. EPA is presently undertaking a comprehensive data collection effort to obtain industry profile information, retrofit costing information for reinjection, and information on the extent of biocide and other chemical use for existing facilities. This information will be analyzed by the Agency to develop appropriate effluent limitations for the BAT level of control.

Drilling Fluids. The Agency is proposing BAT for drilling fluids. The proposed standards include the following limitations:

- A prohibition on the discharge of free oil, oil-based drilling fluids, and diesel oil, all considered as "indicators" of toxic pollutants, including benzene, toluene, ethylbenzene, naphthalene, and phenanthrene.
- A 96-hour LC-50 toxicity limitation on discharged drilling fluids of no less than 3.0 percent by volume of the diluted suspended particulate phase, as defined in the proposed Drilling Fluids Toxicity Test presented in Appendix C.
- A maximum limitation (i.e., no single sample to exceed) on the amount of cadmium and mercury in the discharged drilling fluids of 1 mg/kg dry weight each.

As with NSPS, the prohibitions on oil will be used as "indicators" of toxic pollutants. The Agency believes it is appropriate to establish these prohibitions as BAT toxic limitations. The primary purpose is to control the toxic pollutants present in the oils.

In addition, the Agency is proposing a different definition of the term "no discharge of free oil" and a test procedure for determining compliance with the no free oil requirement as with NSPS.

Drill Cuttings. The Agency has selected BAT for drill cuttings that would prohibit the discharge of free oil, drill cuttings associated with oil-based drilling fluids, and diesel oil. These prohibitions would reduce the discharge of toxic and nonconventional pollutants.

Deck Drainage. The Agency has selected BAT for deck drainage equal to the BPT level of control. This would result in a prohibition on the discharge of free oil as an "indicator" to reduce or eliminate the discharge of any toxic pollutants in the free oil to surface waters. The technology basis is oil-water separation. BAT compliance costs incremental to BPT consist of additional compliance monitoring expenditures of $1.09 million (1983 dollars) annually, reflecting use of the proposed static sheet test to determine compliance with the prohibition on the discharge of free oil.

The Agency is reserving coverage of all other toxic and nonconventional pollutant parameters and characteristics for deck drainage pending additional data collection and analysis. This additional data will include toxic pollutant information and control and treatment technology evaluation.

Sanitary Wastes and Domestic Wastes. The Agency is not establishing BAT effluent limitations for these waste streams because there have been no toxic or nonconventional pollutants of concern identified in sanitary or domestic wastes.

Produced Sand. The Agency is establishing a BAT prohibition on the discharge of free oil for produced sand as an "indicator" to reduce or eliminate the discharge of any toxic pollutants in the free oil to surface waters. The technology basis for this limitation is water or solvent wash of produced sand prior to discharge, or transport of produced sand to shore for land disposal. Coverage of all other pollutant parameters is being reserved pending additional data collection and evaluation. Because this waste stream is of low volume and because most facilities currently practice either washing or land disposal, the Agency did not attribute any compliance costs to this proposed limitation, except for nominal compliance monitoring expenses to perform the static sheen test to determine the presence of free oil.

Well Treatment Fluids. The Agency is establishing a BAT prohibition on the discharge of free oil for well treatment fluids as an indicator to reduce or eliminate the discharge of any toxic pollutants in the free oil to surface waters. This is equal to the BPT level of control. Therefore, there are no compliance costs incremental to BPT, except for nominal compliance monitoring expenses to perform the static sheen test to determine the presence of free oil.

The Agency is reserving BAT coverage for well treatment fluids for all other pollutants pending additional data collection and evaluation. This additional data will include toxic and nonconventional pollutant information and control and treatment technology evaluation.

Table I-3 summarizes effluent limitations for BAT.

Best Conventional Technology (BCT)

Produced Water. The Agency has established BCT for produced water at the BPT level of control. This would result in effluent limitations of 48 mg/l monthly average and 72 mg/l daily maximum for oil and grease, based upon oil water separation technologies.

Table I-3

BAT Effluent Limitations

Waste Source	Pollutant Parameter or Characteristic	BAT Effluent Limitations
Produced water	[Reserved]	[Reserved]
Deck drainage	Free oil	No discharge
	[All other pollutants - reserved]	
Drilling fluids	Free oil	No discharge
	Oil-based fluid	No discharge
	Diesel oil	No discharge in detectable amounts
	Toxicity	96-hr LC-50 of the diluted suspended particulate phase (SPP) of the drilling fluid shall not be less than 3.0 percent by volume
	Cadmium	1 mg/kg dry weight maximum in the whole drilling fluid
	Mercury	1 mg/kg dry weight maximum in the whole drilling fluid
Drill cuttings	Free oil	No discharge
	Oil-based fluid	No discharge
	Diesel oil	No discharge in detectable amounts
Sanitary M10	None	-
Sanitary M9IM	None	-
Domestic waste	None	-
Produced sand	Free oil	No discharge
	[All other pollutant parameters reserved]	
Well Treatment fluids	Free oil	No discharge
	[All other pollutant parameters reserved]	

The Agency intends to evaluate reinjection technology for BCT after collection of certain additional technology and cost information prior to promulgation of the final regulations. The Agency may also re-evaluate the proposed BCT limitations for produced water when the final BCT methodology is promulgated.

Drilling Fluids, Drill Cuttings, Deck Drainage and Well Treatment Fluids. With one exception, the Agency is reserving BCT requirements for drilling fluids, drill cuttings, deck drainage and well treatment fluids until final promulgation of the general BCT methodology. The exception is a prohibition on the discharge of free oil. This limitation is equal to the BPT level of control for these waste streams. Therefore, no incremental costs are associated with this proposed BCT limitation. Because BCT is proposed to be equal to BPT, the free oil discharge prohibition will pass any BCT cost test. When the final BCT methodology is promulgated, the Agency may propose to establish BCT limitations for other conventional pollutants for these waste streams.

Domestic and Sanitary Wastes. The Agency is proposing BCT coverage for sanitary and domestic wastes equal to the BPT level of control. The Agency is proposing a residual chlorine effluent limitation for facilities continuously manned by 10 or more persons of 1 mg/l minimum and maintained as close to this level as possible in sanitary discharges to control fecal coliform. Residual chlorine is being treated as a BCT parameter because its purpose is to control the conventional pollutant fecal coliform.

The proposed BCT limitation for domestic wastes from all facilities and sanitary wastes from facilities continuously manned by 9 or fewer persons or manned intermittently by any number of persons is "no discharge of floating solids." No compliance costs incremental to BPT are associated with the proposed BCT limitations. Since no additional costs will be incurred these limitations pass the BCT cost tests.

Produced Sand. With one exception, the Agency is reserving BCT coverage for produced sand until the promulgation of the final BCT methodology. The Agency is proposing a BCT limitation that would prohibit the discharge of free oil for produced sand discharges. As discussed above for BAT, this limitation would result in negligible compliance costs.

Table I-4 summarizes effluent limitations for BCT.

Best Practical Technology (BPT)

For NSPS and BAT, the Agency is proposing to amend its existing definition of the term "no discharge of free oil" for this industrial subcategory. For consistency, the Agency is proposing the same definition change for the existing BPT regulations. This change does not affect the conclusión that the current BPT limitation of no discharge of free oil may be met through use of the best practicable control technology currently available and that the costs of that technology are justified by the effluent reduction benefits.

Cost and Economic Impact

No price changes or curtailment of oil or gas production is expected as a result of the proposed regulations. In addition, no employment or international trade effects are projected.

Table I-4

BCT Effluent Limitations

Waste Source	Pollutant Parameter or Characteristic	BCT Effluent Limitations	
		Maximum for any one day	Average of Daily values for 30 consecutive days shall not exceed
Produced water	Oil and grease	72 mg/l	48 mg/l
Deck drainage	Free Oil [All other pollutant parameters reserved]	No discharge	
Drill cuttings	Free oil [All other pollutant parameters reserved]	No discharge	
Sanitary M10	Residual Chlorine[1]	Minimum of 1 mg/l and maintained as close to this concentration as possible	
Sanitary M9IM	Floating solids	No discharge	
Domestic waste	Floating solids	No discharge	
Produced sand	Free oil [All other pollutant parameters reserved]	No discharge	
Well treatment fluids	Free oil [All other pollutant parameters reserved]	No discharge	

[1] For the control of fecal coliform

II. INTRODUCTION

PURPOSE AND AUTHORITY

This development document details the technical basis for the Agency's proposed effluent limitations guidelines and standards reflecting NSPS, BAT and BCT and certain amendments to BPT for the offshore segment of the oil and gas extraction point source category.

The regulations described in this development document are proposed under the authority of Sections 301, 304, 306, 307, and 501 of the Clean Water Act (the Federal Water Pollution Control Act Amendments of 1972, 33 U.S.C. 1251 et seq., as amended by the Clean Water Act of 1977, Pub. L. 95-217). These regulations are also proposed in response to the Court Order in Natural Resources Defense Council, Inc. v. Costle, No. 79-3442 (D.D.C.) July 7, 1980.

LEGAL BACKGROUND

The Federal Water Pollution Control Act Amendments of 1972 established a comprehensive program to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters", and declared in Section 101(a) that it is a national goal to eliminate "the discharges of pollutants into the navigable waters." By July 1, 1977, existing industrial dischargers were required to achieve "effluent limitations requiring the application of the best practicable control technology currently available" (BPT), as specified in Section 301(b)(1)(A). By July 1, 1983, these dischargers were required to achieve "effluent limitations requiring the application of the best available technology economically achievable (BAT), which will result in reasonable further progress toward the national goal of eliminating the discharge of pollutants", as specified in Section 301(b)(2)(A). New industrial direct dischargers were required to comply with new source performance standards (NSPS), as specified in Section 306, based on best available demonstrated technology. New and existing dischargers to publicly owned treatment works (POTWs) were subject to pretreatment standards under Sections 307(b) and (c). While the requirements for direct dischargers were to be incorporated into National Pollutant Discharge Elimination System (NPDES) permits issued under Section 402 of the Act, pretreatment standards were made enforceable directly against dischargers to POTWs (indirect dischargers).

Although Section 402(a)(1) of the 1972 Act authorized the setting of requirements for direct dischargers on a case-by-case basis in the absence of regulations, Congress intended that, for the most part, control requirements would be based on regulations promulgated by the Administrator of EPA. Section 304(b) of the Act required the Administrator to promulgate regulations providing guidelines for effluent limitations setting forth the degree of effluent reduction attainable through the application of BPT and BAT. Moreover, Sections 304(c) and 306 of the Act required promulgation of regulations for NSPS, and Sections 304(f), 307(b), and 307(c) required promulgation of regulations for pretreatment standards. In addition to these regulations for designated industry categories, Section 307(a) of the Act required the Administrator to promulgate effluent standards applicable to all dischargers of toxic pollutants. Finally, Section 501(a) of the Act authorized the Administrator to prescribe any additional regulations "necessary to carry out his functions" under the Act.

EPA was unable to promulgate many of these toxic pollutant regulations and guidelines within the time periods stated in the Act. In 1976, EPA was sued by several environmental groups and, in settlement of this lawsuit, EPA and the plaintiffs executed a "Settlement Agreement," which was approved by the Court. This Agreement required EPA to develop a program and adhere to a schedule for promulgating, for 21 major industries, BAT effluent limitations guidelines, pretreatment standards, and new source performance standards for 65 toxic pollutants and classes of toxic pollutants. See Natural Resources Defense Council, Inc. v. Train, 8 ERC 2120 (D.D.C. 1976), modified 12 ERC 1833 (D.D.C. 1979), modified by additional orders of October 26, 1982, August 2, 1983, and January 6, 1984.

On December 27, 1977, the President signed into law the Clean Water Act of 1977. Although this law makes several important changes in the Federal water pollution control program, its most significant feature is its incorporation into the Act of many of the basic elements of the Settlement Agreement program for toxic pollution control. Sections 301(b)(2)(A) and 301(b)(2)(C) of the Act now require the achievement by July 1, 1984, of effluent limitations requiring application of BAT for "toxic" pollutants, including the 65 "priority" pollutants and classes of pollutants which Congress declared "toxic" under Section 307(a) of the Act. Likewise, EPA's programs for new source performance standards and pretreatment standards are now aimed principally at toxic pollutant controls. Moreover, to strengthen the toxics control program, Congress added a new Section 304(e) to the Act, authorizing the Administrator to prescribe what have been termed "best management practices" (BMPs) to prevent the release of toxic pollutants from plant site runoff, spillage or leaks, sludge or waste disposal, and drainage from raw material storage associated with, or ancillary to, the manufacturing or treatment process.

The Clean Water Act of 1977 also revised the control program for non-toxic pollutants. Section 301(b)(2)(E) now requires achievement by July 1, 1984 of "effluent limitations requiring the application of the best conventional pollutant control technology" (BCT) for discharges of conventional pollutants from existing industrial point sources. Conventional pollutants are those mentioned specifically in Section 304(a)(4) (biochemical oxygen demanding pollutants (BOD5), total suspended solids (TSS), fecal coliform, and pH), and any additional pollutants defined by the Administrator as "conventional". On July 30, 1979, the Agency designated oil and grease as a conventional pollutant (44 FR 44501).

For non-toxic, nonconventional pollutants, Sections 301(b)(2)(A) and (B)(2)(F) require achievement of BAT effluent limitations within three years after their establishment or July 1, 1984, whichever is later, but not later than July 1, 1987.

PRIOR EPA REGULATIONS

On September 15, 1975, EPA promulgated effluent limitations guidelines for interim final BPT (40 FR 42543) and proposed regulations for BAT, NSPS, and pretreatment standards (40 FR 42572) for the offshore segment of the oil and gas extraction point source category. The Agency promulgated final BPT regulations for the offshore segment on April 13, 1979 (44 FR 22069), but deferred action on regulations for BAT, NSPS, and pretreatment standards.

The Natural Resources Defense Council filed suit on December 29, 1979 seeking an order to compel the Administrator to promulgate final NSPS for the offshore subcategory. In settlement of NRDC v. Costle, No. 79-3442 (D.D.C.), the Agency acknowledged the statutory requirement and agreed to take steps to issue such standards. However, because of the length of time that had passed since proposal, EPA believed that examination of additional data and reproposal were necessary. Consequently, the Agency withdrew the proposed NSPS on August 22, 1980 (45 FR 56115). The proposed guidelines for BAT and pretreatment standards were also withdrawn on March 19, 1981 (46 FR 17567).

Ocean discharge criteria also applicable to this industry segment were promulgated on October 3, 1980 (45 FR 65942) under Section 403(c) of the Act. These 403(c) guidelines are to be used in making site specific assessments of the impact of discharges; Section 403 limitations are imposed through Section 402 NPDES permits. Section 403 is intended to prevent unreasonable degradation of the marine environment and to authorize imposition of effluent limitations, including a prohibition of discharge, if necessary, to ensure this goal.

Offshore oil and gas facilities may also be required to prepare and implement spill prevention control and countermeasure (SPCC) plans under Section 311(j) of the Act. These requirements are set forth at 40 CFR Part 112.

SCOPE OF THIS RULEMAKING

The purpose of this rulemaking is to propose BAT, BCT, NSPS, and certain amendments to BPT for the offshore segment of the oil and gas extraction industry. EPA's earlier rulemaking efforts emphasized the achievement of BPT. In general, BPT represents the average of the best existing performances of well known technologies for control of traditional (i.e., "classic") pollutants by facilities of various sizes and ages within an industrial category or subcategory. In establishing BPT limitations, EPA considers the total cost of applying the technology in relation to the effluent reduction derived, the age of equipment and facilities involved, the process employed, the engineering aspects of control technologies, process changes, and nonwater quality environmental impacts (including energy requirements) and other factors the Administrator considers appropriate. The total cost of applying the technology is balanced against the effluent reduction.

BPT effluent limitations guidelines, promulgated in 1979 for this industry segment, limit the discharge of oil and grease in produced water to a daily maximum of 72 mg/1 and a thirty day average of 48 mg/1; prohibit the discharge of free oil in deck drainage, drilling fluids, drill cuttings, and well treatment fluids; require a minimum residual chlorine content of 1 mg/1 in sanitary discharges; and prohibit the discharge of floating solids in sanitary and domestic wastes. The only portions of the BPT guidelines for which amendments are being proposed in the present rulemaking are the definition of "no discharge of free oil."

This rulemaking also aims for the achievement of BAT that will result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants. BAT limitations, in general, represent the best existing performance of technology in an industrial category or subcategory. Moreover, as a result of the Clean Water Act of 1977, the emphasis of EPA's program has shifted from "classical" pollutants to the control of listed toxic pollutants. The Act established BAT as the principal national means of controlling the direct discharge of toxic and nonconventional pollutants to navigable waters.

The factors considered in assessing BAT include the age of equipment and facilities involved. the process employed, process changes, nonwater quality environmental impacts (including energy requirements) and the costs of applying such technology. At a minimum, the BAT level represents the best economically achievable performance of plants of various ages, sizes, processes or other shared characteristics. As with BPT, where the Agency has found the existing performance to be uniformly inadequate, BAT may be transferred from a different industrial category or subcategory. BAT may include feasible process changes or internal controls, even when not in common industry practice.

The statutory assessment of BAT "considers" costs, but does not require a balancing of costs against pollutant removal benefits. In developing the proposed BAT, however, EPA has given substantial weight to the reasonableness of cost. The Agency has considered the volume and nature of discharges expected after application of BAT, the general environmental effects of the pollutants, and the costs and economic impacts of the required pollution control levels. Despite this expanded consideration of costs, the primary determinant of BAT is still pollutant removal capability.

The BAT effluent limitations guidelines being proposed in the present rulemaking would prohibit the discharge of free oil in drilling fluids, deck drainage, drill cuttings, and produced sand; prohibit the discharge of drilling fluids that are oil-based or that contain diesel oil; prohibit the discharge of drill cuttings that are contaminated with diesel oil or that are generated with the use of drilling fluids that are oil-based; limit the acute toxicity of drilling fluid discharges to a minimum 96-hr LC-50 (lethal concentration to 50 percent of the test organisms) of 3 percent by volume (30,000 ppm) as measured in the diluted suspended particulate phase (SPP); and limit the discharge of cadmium and mercury in drilling fluids to a maximum of 1 mg/kg dry weight, each (whole fluid basis). BAT effluent limitations guidelines for produced water, and for deck drainage, produced sand and well treatment fluids for pollutants other than free oil are being reserved for future rulemaking.

The Agency has included proposed BCT effluent limitations guidelines in the present rulemaking. BCT is not an additional limitation, but replaces BAT for the control of conventional pollutants. In addition to other factors specified in Section 304(b)(4)(B), the Act requires that BCT limitations be assessed in light of a two part "cost-reasonableness" test, American Paper Institute v. EPA, 660 F.2d 954 (4th Cir. 1981). The "POTW test" compares the cost for private industry to reduce its conventional pollutants with the costs to publicly owned treatment works for similar levels of reduction in their discharge of these pollutants. The "industry cost test" examines the cost-effectiveness of additional industrial treatment beyond BPT. EPA must find that limitations are "reasonable" under both tests before establishing them as BCT. In no case may BCT be less stringent than BPT.

EPA published its methodology for carrying out the BCT analysis on August 29, 1979 (44 FR 50372). In the case mentioned above, the Court of Appeals ordered EPA to correct data errors underlying EPA's calculation of the first test, and to apply the second cost test, which EPA had argued was not required. The Agency proposed a revised BCT methodology on October 19, 1982 (47 FR 49176). On September 20, 1984, EPA noticed the availability of new data and analyses that it was considering for the development of BCT limitations (49 FR 37046).

The BCT effluent limitations guidelines being proposed in this rulemaking are equal to the previously promulgated BPT guidelines. The Agency is, however, reserving BCT coverage of additional conventional pollutant parameters in deck drainage, drilling fluids, drill cuttings, well treatment fluids, and produced sand waste streams for future rulemaking.

Performance standards for new sources are also included in this proposed rulemaking. The basis for NSPS under Section 306 of the Act is the best available demonstrated technology. New facilities have the opportunity to include the best and most efficient wastewater treatment technologies in their designs. Therefore, Congress directed EPA to consider the best demonstrated process changes and end-of-pipe treatment technologies that reduce pollution to the maximum extent feasible.

The proposed NSPS for this industry segment are the same as the Agency's proposed BAT/BCT effluent limitations guidelines with one exception. EPA is proposing a prohibition on the discharge of produced water from all oil production facilities located in shallow water areas as defined in the regulation. Produced water discharges from all other offshore facilities engaged in exploration, development, and production activities would be limited to a maximum oil and grease concentration of 59 mg/1.

No pretreatment standards have been promulgated for the offshore segment of this industry, and EPA does not intend to propose such standards in this rulemaking. This is because the Agency is not aware of any existing or planned indirect dischargers in the offshore segment.

OVERVIEW OF THE INDUSTRY

Industry Profile

The offshore segment of the oil and gas extraction point source category covers those facilities located off the coast of the United States that are engaged in the production of crude petroleum and natural gas, the drilling of oil and gas wells, and oil and gas field exploration services. Such offshore activities are included in the Standard Industrial Classification (SIC) Major Group 13. Facilities, such as exploratory rigs, drilling platforms, and production platforms that are engaged in these activities, are considered offshore facilities if they are located in waters that are seaward of the inner boundary of the territorial seas, as identified in Section 502 of the Act. This boundary is defined as the line of ordinary low ater along that portion of the coast which is in direct contact with the open sea and the line marking the seaward limit of inland waters.

California and Alaska. In 1982 over 405 million barrels of oil and 4.7 trillion cubic feet of gas with a market value of almost $23 billion were produced offshore. These quantities represent 15 percent and 25 percent, respectively, of the total oil and gas produced in the United States. The combined bonus payments and royalties paid to the Federal government for offshore leases totaled almost $10 billion in 1981.

The majority of existing U.S. operations are located in the Gulf of Mexico. However, exploration and development activities are expected to expand in the California, Alaska, and Atlantic coast regions. For example, large potential petroleum reserves have been discovered at Point Arguello, California and in the Beaufort Sea, Alaska. Results of exploration drilling to date for the Atlantic outer continental shelf (OCS) areas and the Gulf of Alaska have not demonstrated significant petroleum reserves. The lack of geologic data to confirm the presence of economically recoverable oil or gas make development projections for these areas less certain.

Offshore drilling activity varies from year to year depending on such factors as hydrocarbon market conditions, state and federal leasing programs, reservoir discoveries, and the strategic planning decisions and financial health of companies within the industry. In 1981 there were almost 1500 wells drilled offshore, culminating a steady upward trend throughout the 1970's. The average number for the period 1972-82 is approximately 1100 wells per year. Drilling rig utilization declined in 1982, and activity is not expected to improve significantly for some time, especially with the current downturn in crude oil prices.

EPA estimates that approximately 833 new source oil and gas platforms will be constructed between 1986 and the year 2000 in offshore U.S. waters. The Agency distinguishes between oil facilities and gas facilities (platforms) in the following manner. The wells associated with an oil facility are either all oil wells, or include both oil and gas wells; the wells associated with a gas facility include gas wells only.

Exploration, Development, and Production Industry Activities

Offshore oil and gas operations can be classified into exploration, development, and production activities. These operations generate waste discharges that include principally produced water, deck drainage, drilling fluids, drill cuttings, well treatment fluids, produced sand, and sanitary and domestic wastes.

Exploration activities are those operations involving the drilling of wells to determine the nature of potential hydrocarbon reservoirs. These operations are usually of short duration at a given site, involve a small number of wells and are generally conducted from mobile drilling units. Discharges are composed mostly of drilling fluids and drill cuttings.

Development activities involve the drilling and completion of production wells once a hydrocarbon reserve has been identified. These operations usually involve a large number of wells and are typically conducted from a fixed platform. Discharges include drilling fluids, drill cuttings, and well treatment fluids.

Production activities begin as each well is completed during the development phase. The production phase involves active recovery of hydrocarbons from producing formations. Development and production activities may occur simultaneously until all wells are completed or reworked. Produced water waste streams are the most significant discharges during production operations.

Drilling fluids (muds) are those materials used to maintain hydrostatic pressure control in the well, lubricate the drill bit, remove drill cuttings from the well, and stabilize the walls of the well during drilling.

Drill cuttings are the solids resulting from drilling into subsurface geologic formations, and are brought to the surface of the well in the drilling fluid system.

Well treatment fluids are used in stimulating a hydrocarbon-bearing formation or in reworking a well to increase or restore productivity and in completing a well for oil and gas production.

Produced water (brine) is brought up from the hydrocarbon-bearing strata along with produced oil and gas, and can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process.

Produced sand consists of the accumulated formation sands generated during production and the slurried particles used in hydraulic fracturing.

Deck drainage includes all waste resulting from platform washings, deck washings, rainwater, and runoff from curbs, gutters, and drains.

Sanitary wastes originate from toilets and domestic wastes originate from sinks, showers, laundries, and galleys located on drilling and production facilities.

SUMMARY OF METHODOLOGY

In developing effluent regulations for this industry segment, EPA first studied the industry to determine whether differences in factors such as production methodology, location and type of operation, size and age of facility, and waste constituents require separate limitations and standards for different segments of the category. This study involved an evaluation of how these factors affect raw waste loads, and the identification of raw waste and treated effluent characteristics, including sources and volumes of waste streams. The Agency then determined the waste constituents, including toxic pollutants, which should be considered for effluent limitations guidelines and standards of performance.

EPA also identified both presently used and potential control and treatment technologies that can be applied within each industry segment. The Agency compiled and evaluated both historical and newly generated data on the performance and operational limitations of these technologies. In addition, EPA considered the impacts of these technologies on air quality, solid waste generation, and energy requirements.

The Agency also estimated capital and annual costs associated with each control and treatment alternative. In general, unit process costs were derived by using data on production and waste characteristics for model facilities to develop unit process costs for various control and treatment steps. These unit process costs were then combined to yield a total cost for various treatment levels. The Agency was then able to determine total industry costs, evaluate the costs of applying alternative technologies, and assess the economic impacts of compliance for each regulatory option considered.

Consideration of these factors enabled EPA to classify the various control and treatment technologies as a basis for NSPS, BAT, and BCT regulations. The proposed regulations, however, do not require the application of any particular technology. Rather, they require compliance with effluent limitations and standards that could be attained through the proper operation of these or equivalent technologies.

DATA GATHERING EFFORTS

Existing Information

After the proposed NSPS were withdrawn in 1980 in accordance with the Court Order in NRDC v. Costle, the Agency conducted an assessment of existing information related to point source discharges from the offshore segment of the industry. This included profiles of current and projected offshore drilling and production activities, regulatory history and enforcement status, waste characterization, existing and potential control and treatment technologies, and cost, energy and non-water quality impact of discharge control. Existing data were assembled through contacts with EPA regional offices, other Federal and State government agencies, industry associations, industry representatives, third party oil transmission pipeline companies, solid waste dump site operators, drill cuttings washer suppliers, equipment manufacturers, and various technical publications.

Additional Data Collection

Several areas were identified that required further study to support the reproposal of effluent limitations guidelines and standards. These included an evaluation of priority pollutant levels in produced water discharges, an evaluation of alternative control and treatment technologies for reducing the discharge of priority pollutants, a characterization of drilling fluids and additives presently in use, an investigation of alternative disposal practices for drilling fluids and drill cuttings, an assessment of the impacts of discharging drilling and production wastes to the marine environment in general, and updated projections on the location, size and configuration of new sources.

Sampling and Analytical Programs

The sampling and analysis programs conducted for this rulemaking have focused on produced water and drilling fluids and cuttings, and on the toxic pollutants designated in the Clean Water Act. However, EPA sampled and analyzed wastes in the offshore subcategory for certain conventional and nonconventional pollutants as well as inorganic and organic toxic pollutants. Analyses for priority pollutants during the development of today's proposed regulation were based on a number of the proposed methods (44 FR 69464, 44 FR 75028). The final analytical methods were published on October 26, 1984 (49 FR 43234).

Produced Water. The Agency's initial effort to investigate priority pollutants in produced water consisted of a preliminary screening survey conducted at six production platforms in the Gulf of Mexico during 1980. Results obtained by using the standard procedures being proposed by EPA at that time indicated the presence of toxic organics and metals. However, produced waters are brines which may contain significant concentrations of dissolved salts. The nature of this waste stream required the Agency to develop modified or unique analytical methods.

Representatives of the Offshore Operators Committee (OOC), the American Petroleum Institute, and EPA cooperated in a joint effort in 1981 to develop analytical protocols to measure toxic pollutants in produced water.

During the first of a two-phase analytical program, produced water samples were collected at two production platforms in the Gulf of Mexico and sent to several Agency and industry laboratories for comparative testing. Final analytical protocols were established employing standards purged from ten percent sodium chloride brines, isotope dilution gas chromatography/mass spectrometry (GCMS) for analysis of volatile organic pollutants, continuous and/or acid/neutral extraction and fused silica capillary column isotope dilution GCMS for analysis of semivolatile organic pollutants, and standard addition flame atomic absorption for metals analysis.

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The second phase of the analytical program was conducted with the use of established protocols to confirm the presence and further quantify the concentrations of toxic pollutants in produced water discharges at 30 production facilities in the Gulf of Mexico. Selected conventional and non-conventional parameters were also investigated. Samples were taken of influents to and effluents from produced water treatment systems during visits that ranged from one to three days at individual sites. Strict adherence to specified collection and quality assurance procedures was maintained throughout the program. Additional samples were collected for independent analyses sponsored by the OOC.

Priority pollutant sampling efforts have also been conducted at Alaska and California sites. Produced water samples were collected from both offshore and onshore treatment facilities at Cook Inlet and Prudhoe Bay in Alaska and from three offshore production platforms in California's Santa Barbara Channel.

Drilling Fluids. Another program was initiated by the Agency for this rulemaking to evaluate the characteristics of water-based drilling fluids. Such fluids, or muds, include a variety of compositions used as aids in drilling and stabilizing a borehole in the earth.

One objective of this program was to examine the test procedures that are being proposed as analytical methods applicable to this industrial subcategory for measuring acute toxicity and for detecting the presence of diesel oil in mud discharges. A second objective was to evaluate test results derived from these and other Agency approved analytical procedures in the development of effluent limitations guidelines and standards.

The first phase of this program involved the selection and specification of test muds. The Agency's intent was to select a group of the more commonly used water-based mud formulations for testing purposes. In doing so, the Agency relied on information gathered during the development of NPDES permits issued in 1978 to operators drilling on leases in the Atlantic Ocean. During that effort, eight basic mud types were defined by the Offshore Operators Committee, an industry group working in cooperation with the Agency. These eight generic mud types were selected to encompass virtually all water-based muds, exclusive of specialty additives, used on the Outer Continental Shelf.

Laboratory-prepared muds, based on these eight generic fluid formulations, were sent to EPA laboratories for chemical· physical, and biological testing. Toxicity tests were conducted at EPA's Environmental Research Laboratories using the standard bioassay procedure being proposed with this rulemaking. Analyses for oil content, biochemical oxygen demand, chemical oxygen demand, total organic carbon, and priority pollutants (excluding pesticides) were also performed at EPA contract laboratories.

Drill Cuttings. The discharge of oil and other mud constituents that adhere to or are mixed with waste cuttings is the primary concern in the drill cuttings waste stream. The data gathered on the quality of mud compositions were used to assess the expected effects of the discharge of contaminated drill cuttings to the ocean. In addition, information was obtained from suppliers of various types of cuttings washer systems on projected washer performance and treatment costs. Selected samples of oil contaminated drill cuttings before and after washing were obtained for screening purposes and tested for the same conventional, nonconventional, and some priority pollutant parameters that were investigated during the drilling fluids program.

Other Waste Streams. The Agency did not perform any new sampling or analytical programs for deck drainage, sanitary, domestic, produced sand, and well treatment fluids waste streams. The proposed NSPS, BAT, and BCT regulations for these waste streams are based upon information collected during the development of the existing BPT regulations. Effluent limitations and standards for certain toxic, conventional, and nonconventional pollutants are being reserved for these waste streams pending additional data collection by the Agency.

Environmental Effects Information Collection

The Agency obtained information from numerous sources regarding the general environmental effects of discharges from offshore oil and gas platforms. In November of 1982, EPA issued a draft report entitled, Interim Final Assessment of Environmental Fate and Effects of Discharges from Offshore Oil and Gas Operations which summarized recent literature on the effects of produced water, drilling fluids, drill cuttings, deck drainage and sanitary wastes. Subsequently, the Agency investigated other data sources on produced water including an API report entitled Effects of Oilfield Brine Effluent on Benthic Organisms in Trinity Bay, Texas (API Publication No. 4291) and a more recent draft report titled Ecological Effects of Produced Water Discharges from Offshore Oil and Gas Production Platforms (API project No. 248). Other reports on drilling fluids and cuttings were also reviewed which include, Drilling Discharges in the Marine Environment by the National Research Council and Results of the Drilling Fluids Research Program Sponsored by the Gulf Breeze Environmental Research Laboratory, 1976-1984 and Their Application to Hazard Assessment (EPA Publication 600/4-84-055).

In response to comments on the draft environmental assessment, the Agency has also summarized findings from other studies pertinent to this regulation in the final environmental assessment. This assessment, titled Assessment of Environmental Fate and Effects of Discharges From Offshore Oil and Gas Operations, is included as supporting documentation for today's proposed regulations and supersedes the draft assessment of November 1982. In addition to the discussion of the field studies and other reports, this final assessment discusses the results from the PLUME model which was developed by EPA's Corvallis Environmental Research Laboratory. This model predicts dilution, trap depth and depth of maximum penetration of the produced water discharges.

The Agency has also investigated the following: (1) biocides in use on platforms and rigs; (2) commercial landings of fish and invertebrates and level of effort statistics for the Gulf of Mexico; (3) marine species distributions for the United States; and (4) potential impacts from barite discharges.

An EPA report on biocides titled Biocides in Use on Offshore Oil and Gas Platforms and Rigs is included in the rulemaking record and referenced in the environmental assessment. The other analyses are also summarized in the final environmental assessment supporting the proposed regulations.

Economic Information Collection

The Agency obtained most of the economic data from a variety of secondary sources. Department of Interior publications provided information on offshore leasing, platform development, production and income. Department of Energy publications were used for information on energy development, production and price. Industry trade publications and annual reports were used to construct financial profiles of energy development companies. In addition to the above sources, a number of industry specialists in both the public and private sector provided data and opinions on technical and economic issues.

III. DESCRIPTION OF THE INDUSTRY

INTRODUCTION

The offshore segment of the oil and gas extraction industry produces oil and gas from wells located off the coast of the United States. Offshore development occurs in areas which are offered for development by federal or state governments on a leased basis. Once an area is leased by a company or group of companies, exploration wells are drilled to determine whether hydrocarbons are present. If oil or gas is found in sufficient quantities, development wells and production facilities (platforms) are put in place. From these facilities, oil and gas are produced and conveyed to markets by pipeline or tanker.

This study covers offshore activities included in the Standard Industrial Classifications (SIC) 1311 Crude Petroleum and Natural Gas, 1381 Drilling Oil and Gas Wells, 1382 Oil and Gas Field Exploration Services, and 1389 Oil and Gas Field Services, not classified elsewhere. A facility is considered offshore if it is located within or discharges to waters that are seaward of the inner boundary of the territorial seas. This boundary is defined in Section 502 of the Act as the line of ordinary low water along that portion of the coast which is in direct contact with the open sea and the line marking the seaward limit of inland waters.

The characteristics of wastes generated by the various oil and gas extraction processes and operations differ considerably. In order to describe the wastes derived from the offshore segment of the industry, it is essential to evaluate the sources and contaminants associated with the three broad activities in the industry: exploration, development and production.

EXPLORATION

The exploration process consists of defining and describing geological structures in an area that has potential for hydrocarbon reservoirs. Geological surveys are conducted to map the surface of the earth and to determine the subsurface structure. Measurements made by geophysical methods, such as seismic, gravimetric, and magnetic, give indications of the depth and nature of subsurface rock formations. These surveys can suggest underground conditions favorable to accumulation of oil and gas deposits, but they must be followed by exploratory drilling to prove the actual existence of hydrocarbon deposits.

Although the majority of wells drilled by the petroleum industry are to obtain access to reservoirs of oil or gas, a significant number are drilled to gain knowledge of geologic formations. This latter class of wells may be shallow and drilled in the initial exploratory phase of operations, or may be deep exploration seeking to discover the extent of oil or gas bearing reservoirs. Exploratory drilling, whether shallow or deep, generally uses the same rotary drilling methods as development drilling. The most significant waste streams, in terms of volume and constituents, associated with exploration activities are the drilling muds and cuttings generated during the drilling phase. In 1981 there were almost 1500 wells drilled offshore while 1982 saw a decrease in drilling in response to the crude oil market.

DEVELOPMENT (Well Drilling)

Drilling is the process of actually cutting through the earth's crust to form a well and is accomplished by drill bit rotation and hoisting operations. Basically, the methods consist of machinery to turn a drill bit, to add sections on the drill pipe as the hole deepens, to remove the pipe and bit from the hole;

and a system for circulating a fluid down through the drill pipe and back up the surface.

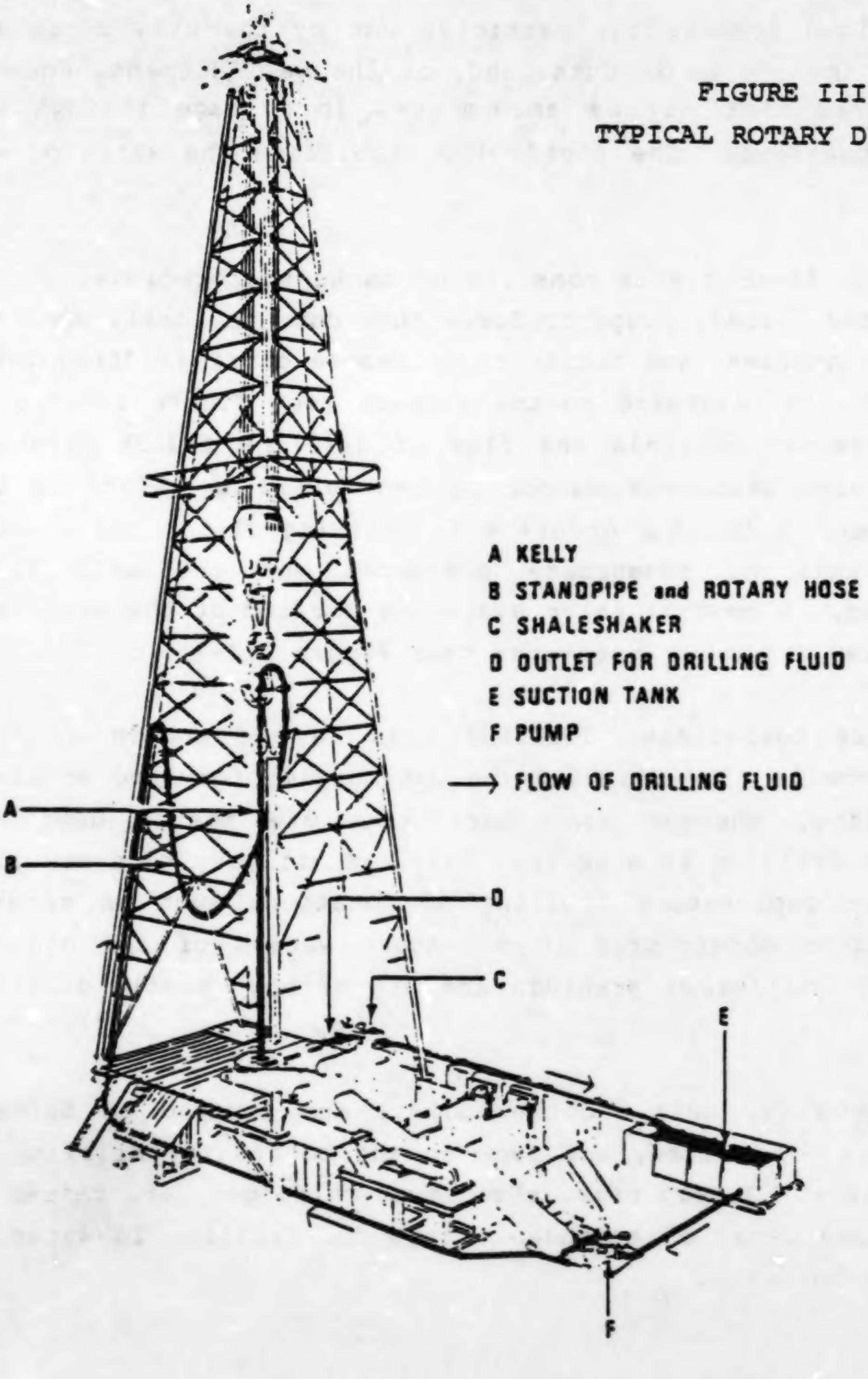
Drilling fluid removes the particles cut by the bit, cools and lubricates the bit as it cuts, and, as the well deepens, equalizes pressures that may be encountered in passage through the various formations. The fluid also stabilizes the walls of the well bore.

The drilling fluid system consists of tanks to formulate, store, and treat the fluids; pumps to force them down the drill pipe and back to the surface; and machinery to remove cuttings, fines, and gas from fluids returning to the surface (see Figure III-1). A system of valves controls the flow of drilling fluids from the well when high pressures cannot be controlled by weight of the fluid column. A blowout occurs when drilling fluids are ejected from the well by subsurface pressures and the well flows uncontrolled. A control valve system is located at the well head and is called a blowout preventer (see Figure III-2).

For offshore operations, drilling rigs may be mobile or stationary. Mobile rigs are used for both exploratory and development drilling, whereas stationary rigs are mostly used for development drilling in a proven field. Stationary rigs may also be used for exploratory drilling at locations such as manmade gravel islands constructed in nearshore waters of the Alaskan Artic where ice forces preclude the use of most mobile drilling rigs.

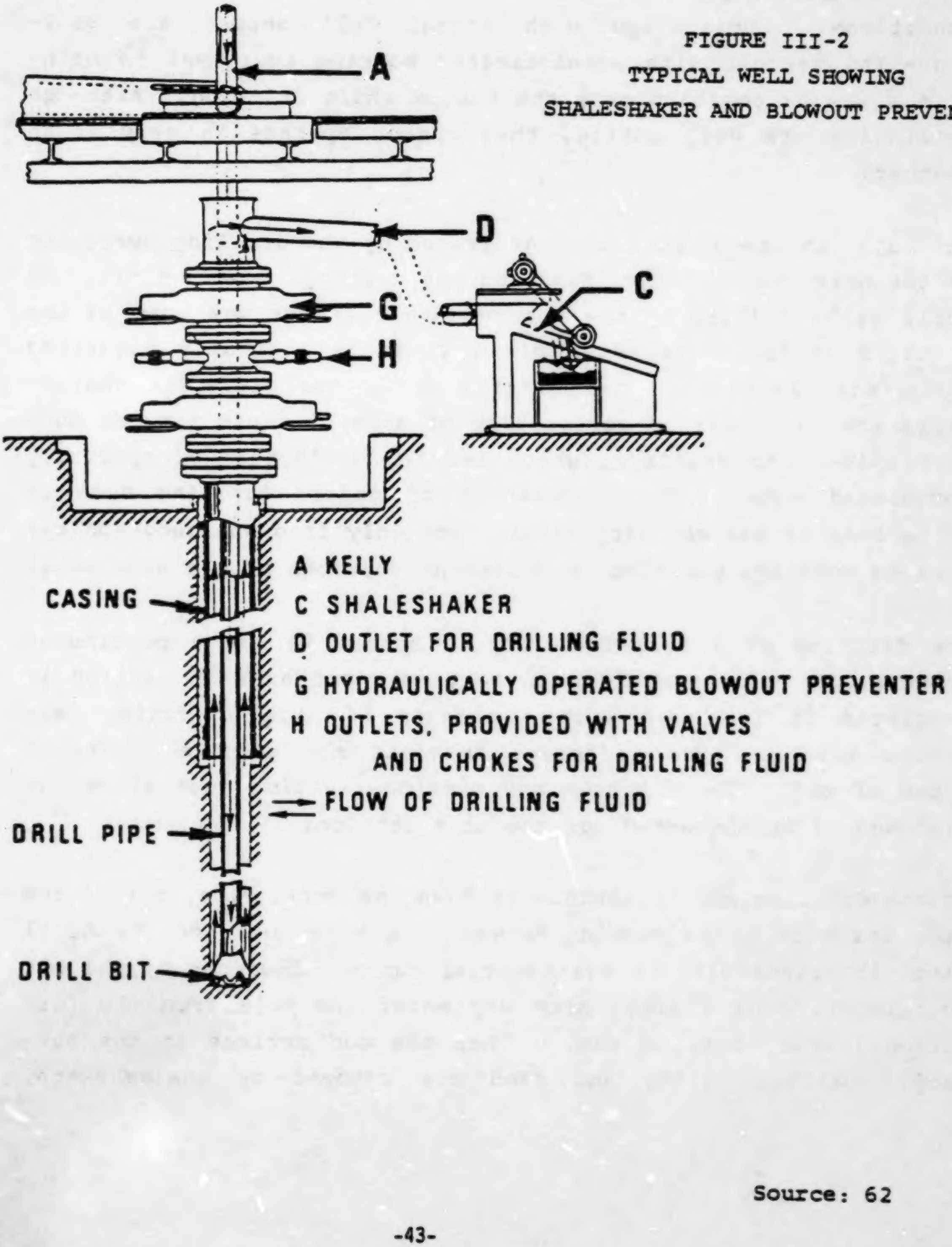
Some mobile rigs, called submersibles, are mounted on barges, towed to the drill site, and sunk on the bottom for drilling in shallow waters. Jackup rigs, also towed on barges, are raised up above the sea level on extendable legs for drilling in water up to 300 feet in depth.

FIGURE III-1
TYPICAL ROTARY DRILLING RIG


A KELLY
B STANDPIPE and ROTARY HOSE
C SHALESHAKER
D OUTLET FOR DRILLING FLUID
E SUCTION TANK
F PUMP
→ FLOW OF DRILLING FLUID
A
B
D
C
E
F

Source: 62

FIGURE III-2
TYPICAL WELL SHOWING
SHALESHAKER AND BLOWOUT PREVENTER


A
D
C
G
H
A KELLY
CASING
C SHALESHAKER
D OUTLET FOR DRILLING FLUID
G HYDRAULICALLY OPERATED BLOWOUT PREVENTER
H OUTLETS, PROVIDED WITH VALVES
AND CHOKES FOR DRILLING FLUID
FLOW OF DRILLING FLUID
DRILL PIPE
DRILL BIT

Source: 62

Semisubmersible rigs on floating structures with submerged ballast chambers that support rigs well above the water are used for deeper operations. These units are anchored in place to provide a relatively stable base, even in severe sea and weather conditions. Drillships with normal hull shapes are self-propelled vessels with sophisticated mooring equipment to maintain a steady position over the bottom while drilling. Although drillships are very mobile, they cannot operate in very rough weather.

The major source of pollution generated by the drilling operation is the drilling fluid or "mud" and the cuttings from the bit. In early wells drilled by the rotary method, water was used as the drilling fluid. The water mixed with the naturally occurring soils and clays which made up the mud. The different characteristics and superior performance of some of these natural muds were evident to drillers, which led to development of specially formulated muds. The composition of modern drilling muds is quite complex and can vary widely, not only from one geographical area to another, but also in different portions of the same well.

The drilling of a well from top to bottom is not a continuous process. A well is drilled in sections, and as each section is completed it is lined with a section of pipe or casing (see Figure III-2). The different sections may require different types of mud. The mud from the previous section must either be disposed of or converted for the next section.

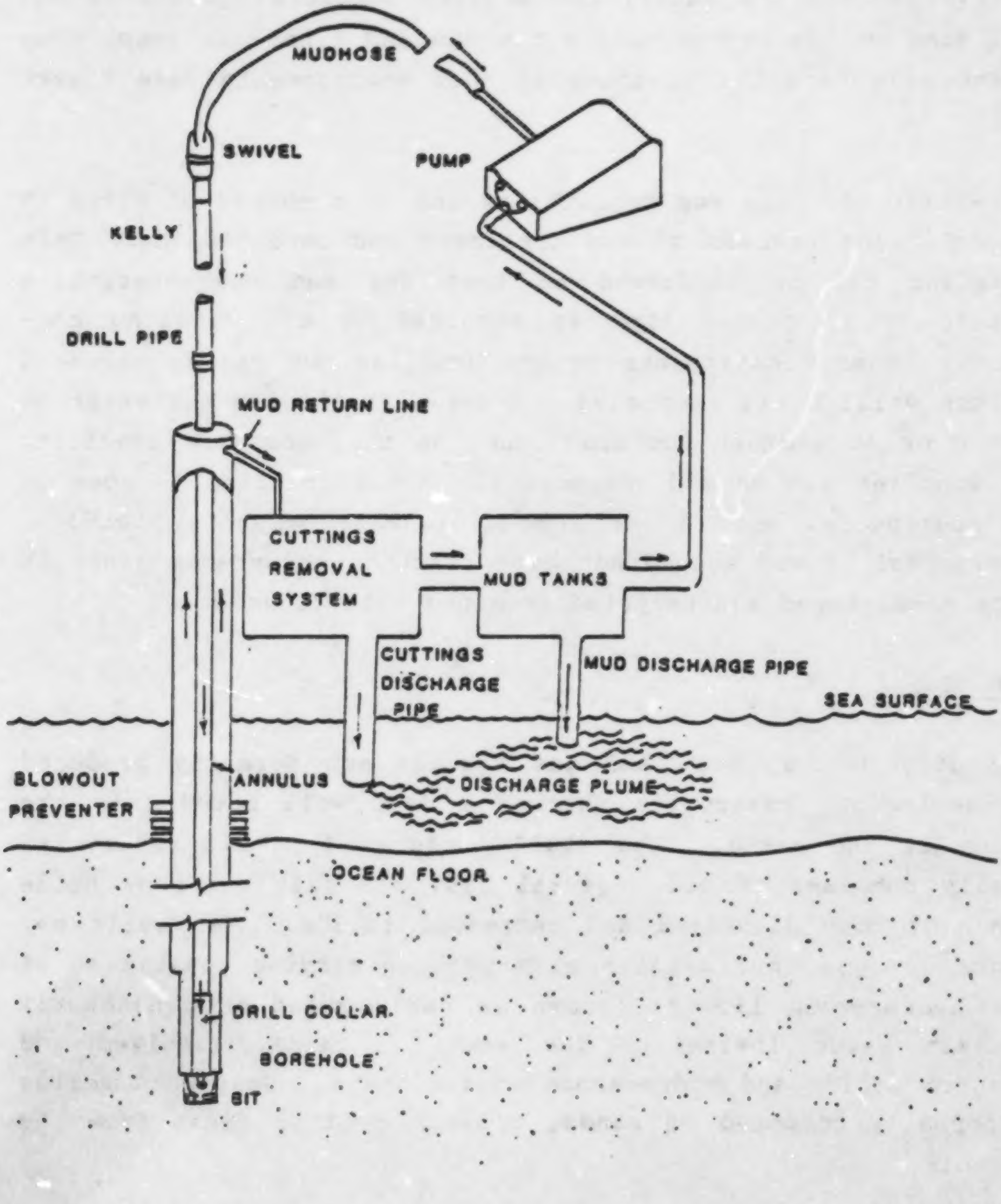
As the drilling mud is circulated down the drill pipe, out of the bit, and back up in annulus between the bore hole and the drill pipe, it brings with it the material cut and loosened by the bit (cuttings), plus fluids which may enter the hole from the formation (water, oil, or gas). When the mud arrives at the surface, cuttings, silt, and sand are removed by shaleshakers, desilters, and desanders. Oil or gas from the formation is also removed and the processed mud is cycled through the drilling system again. With offshore wells, the cuttings, silt, and sand are discharged overboard if they do not contain free oil. Some drilling mud clings to the sand and cuttings and when this material reaches the water, the heavier particles (cuttings and sand) sink to the bottom, while the mud and fines are swept down current away from the platform in most environments (see Figure III-3).

The removal of fines and cuttings is one of a number of steps in the continuing process of mud treatment and conditioning. This processing may be performed to keep the mud characteristics constant or to change them as required by the drilling conditions. Some constituents of the drilling mud can be salvaged when the drilling is completed. Salvage facilities may exist at the rig or at another location, such as the industrial facility that supplies mud or mud components. Where drilling is more or less continuous, such as on a multiple-well offshore platform, the disposal of mud should not be a frequent occurrence since it can be conditioned and recycled from one well to another.

PRODUCTION

Crude oil, natural gas, and gas liquids are normally produced from geological reservoirs through a deep well bored into the surface of the earth. The fluid produced from oil reservoirs normally consists of oil, natural gas, and salt water or brine containing both dissolved and suspended solids. Gas wells may produce dry gas, but usually also produce varying quantities of light hydrocarbon liquids (known as gas liquids or condensate) and salt water (brine). The water contains dissolved and suspended solids and hydrocarbon contaminants. Suspended solids are normally composed of sands, clays, or other fines from the reservoir.

FIGURE III-3
DISCHARGES FROM THE DRILLING OPERATION


MUDHOSE
SWIVEL
PUMP
KELLY
DRILL PIPE
MUD RETURN LINE
CUTTINGS REMOVAL SYSTEM
MUD TANKS
CUTTINGS DISCHARGE PIPE
MUD DISCHARGE PIPE
SEA SURFACE
BLOWOUT PREVENTER
ANNULUS
DISCHARGE PLUME
OCEAN FLOOR
DRILL COLLAR
BOREHOLE
BIT

Source: 254

Crude oil can vary widely in its physical and chemical properties. Two important properties are its density and viscosity. Density is usually measured by the "API Gravity" method which assigns a number to the oil based on its specific gravity. The oil can range from very light gasoline-like materials (called natural gasolines) to heavy, viscous asphalt-like materials.

The fluids are normally moved to the surface through tubing contained within the larger cased bore hole. For oil wells, the energy required to lift the fluids up the well can be supplied by the natural pressures in the formation or it can be provided or assisted by various man-made operations at the surface. The most common methods of supplying man-made energy to extract the oil are: to inject fluids (normally water or gas) into the reservoir to maintain pressure, which could otherwise drop during withdrawal; to force gas into the well stream in order to lighten the column of fluid in the bore and assist in lifting the fluid as the gas expands as it rises to the surface; and to employ various types of pumps in the well itself. As the fluids in the well rise to the surface, they flow through a series of valves and flow control devices which make up the well head.

Once at the surface, the various constituents in the fluids produced by oil and gas wells are separated: gas from the liquids, oil from water, and solids from liquids. Figure III-4 is a schematic representation of the processes used to separate oil, gas, water and solids. This diagram shows the facilities in different locations with the final separation steps located on-shore. In many cases, all or most of the facilities can be located entirely on a platform. The marketable constituents, normally the gas and oil, are then removed from the production area and the wastes, normally the brine and solids, are disposed of after further treatment. At this stage, the gas may still contain significant amounts of hydrocarbon liquids and may require further separation processes.

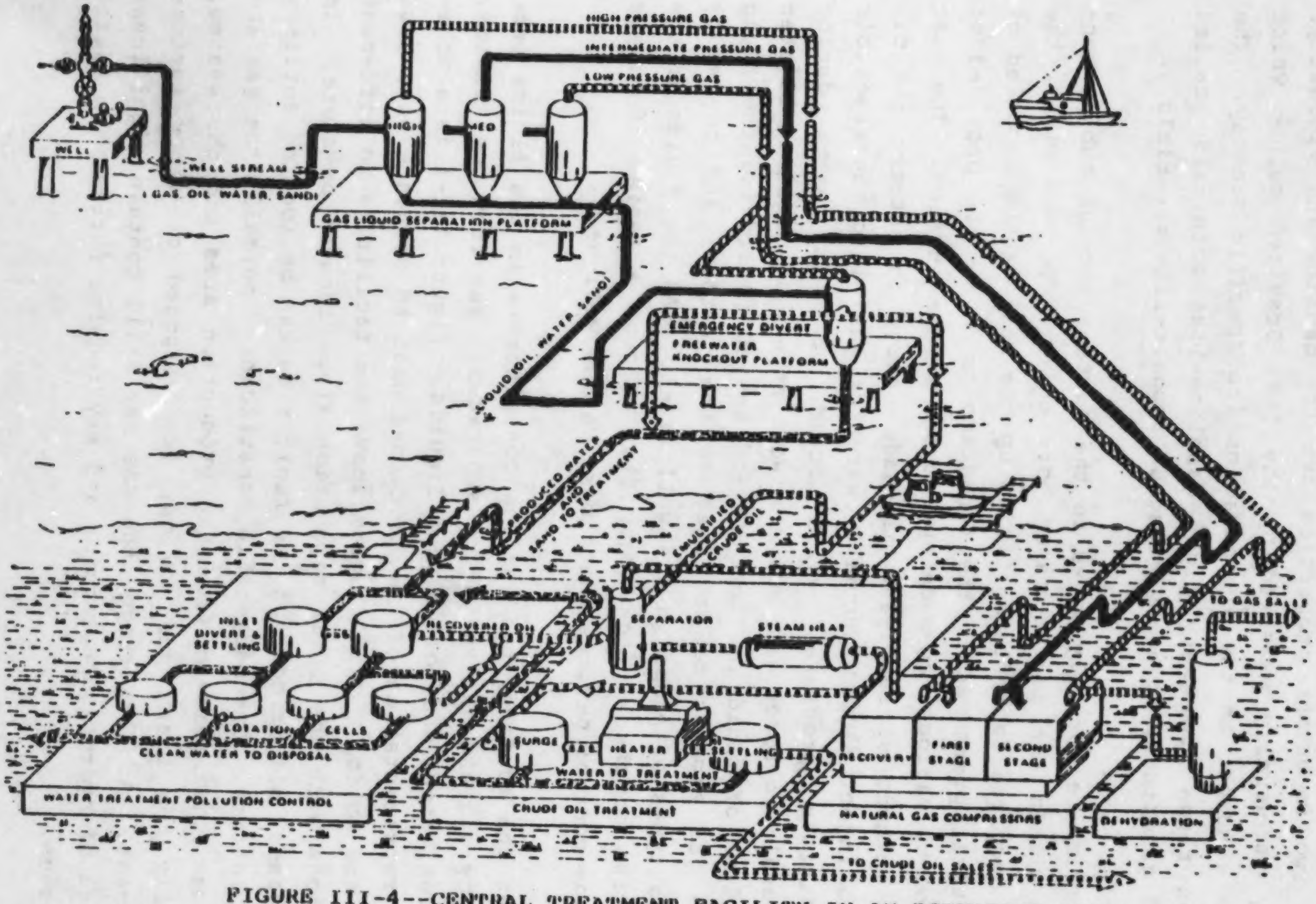

HIGH PRESSURE GAS
INTERMEDIATE PRESSURE GAS
LOW PRESSURE GAS
WELL
WELL STREAM
(GAS, OIL, WATER, SAND)
HIGH
MED
GAS LIQUID SEPARATION PLATFORM
LIQUID (OIL, WATER, SAND)
EMERGENCY DIVERT
FREEWATER KNOCKOUT PLATFORM
PRODUCED WATER AND SAND TO TREATMENT
EMULSIFIED CRUDE OIL
INLET DIVERT & SETTLING
RECOVERED OIL
SEPARATOR
STEAM HEAT
FLOTATION
CELLS
CLEAN WATER TO DISPOSAL
SURGE
HEATER
SETTLING
WATER TO TREATMENT
RECOVERY
FIRST STAGE
SECOND STAGE
TO GAS SALES
WATER TREATMENT POLLUTION CONTROL
CRUDE OIL TREATMENT
NATURAL GAS COMPRESSORS
DEHYDRATION
TO CRUDE OIL SALES

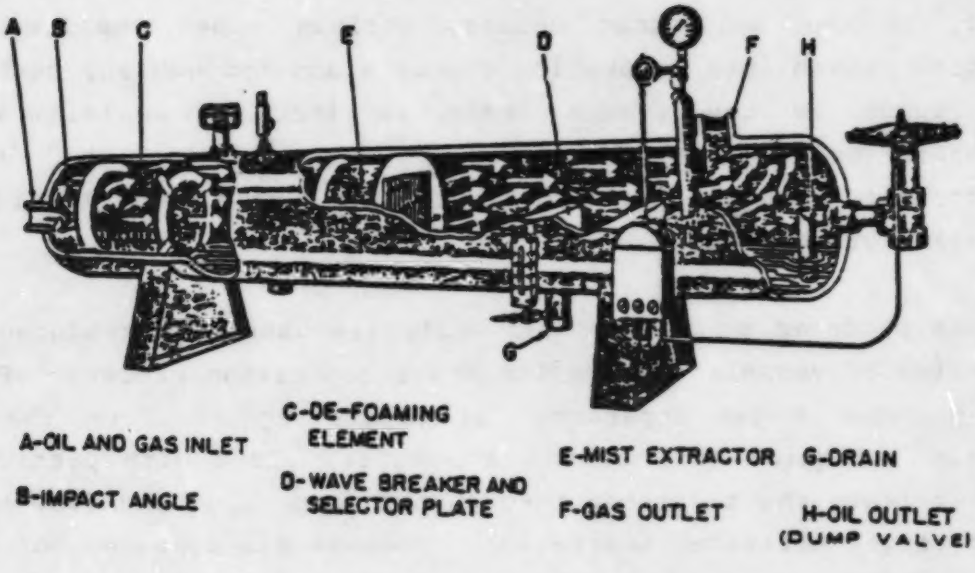
FIGURE III-4--CENTRAL TREATMENT FACILITY IN AN ESTUARINE AREA

Source:3

The gas, oil, and water may be separated in a single vessel or, more commonly, in several stages. Some gas is dissolved in the oil and is released from solution as the pressure on the fluid drops. Fluids from high-pressure reservoirs may have to be passed through a number of separating stages at successively lower pressures before the oil is free of gas. The oil and brine do not separate as readily as the gas does. Usually, a quantity of oil and water is present as an emulsion. This emulsion can occur naturally in the reservoir or can be caused by various processes which tend to vigorously mix the oil and water and causing the emulsion to form. Passage of the fluids into and up the well, through well head chokes, various pipes, headers, and control valves into separation chambers and through any centrifugal pumps in the system tends to increase emulsification. Moderate heat, chemical addition, quiescent settling, and/or electrical charges tend to cause the emulsified liquids to separate or coalesce.

Fluids produced by oil and gas wells are usually introduced into a series of vessels for a multi-stage separation process. Figure III-5 shows a gas separator for separating gas from the well stream. Liquids (oil or oil and water) along with particulate matter leave the separator through the dump valve and flow to the next stage: oil-water separation. Because gas comes out of solution as pressure drops, gas-oil separators are often arranged in series (see Figure III-4). High-pressure, intermediate, and low-pressure separators are the most common arrangement, with the high-pressure liquids passing through each stage in series and gas being taken off at each stage. Fluids from lower-pressure wells would go directly to the most appropriate separator. The liquids are then piped to vessels for separating the oil from the produced water. Fluids which do not contain emulsified oils and separate easily may be treated for water removal in a simple separation vessel called a free water knockout.

FIGURE III-5
HORIZONTAL GAS SEPARATOR


A
B
C
E
D
F
H
G
A-OIL AND GAS INLET
B-IMPACT ANGLE
C-DE-FOAMING ELEMENT
D-WAVE BREAKER AND SELECTOR PLATE
E-MIST EXTRACTOR
F-GAS OUTLET
G-DRAIN
H-OIL OUTLET (DUMP VALVE)

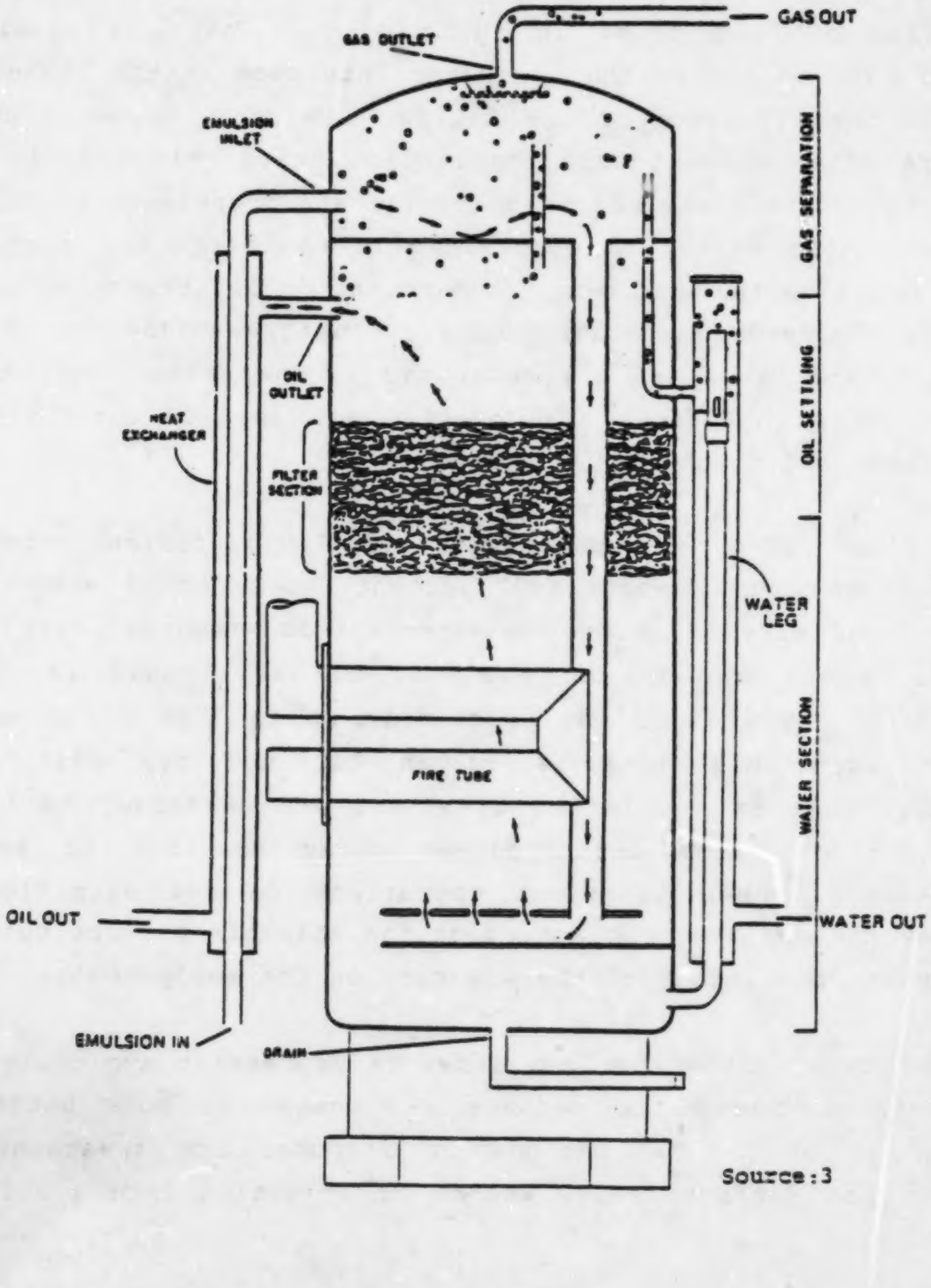
Source: 3

Remaining oil-water mixtures would continue to another vessel for more elaborate treatment (see Figure III-6). In this vessel (which may be called a heater-treater, electric dehydrator, gun barrel, or wash tank, depending on configuration and the separation method employed), there is a relatively pure layer of oil on the top, relatively pure brine on the bottom, and a layer of emulsified oil and brine in the middle. There is usually a sensing unit to detect the oil-water interface in the vessel and regulate the discharge of the fluids. Emulsion breaking chemicals are often added before the liquid enters this vessel. The vessel itself is often heated to facilitate breaking the emulsion and some units employ an electric grid to charge the liquid to aid in breaking the emulsion. A combination of treatment methods is often employed in a single vessel. In three-phase separation, gas, oil, and water are all separated in one unit. The gas-oil and oil-water interfaces are detected and used to control rates of influent and discharge.

Oil from the oil-water separators is usually sufficiently free of water and sediment (less than 2 percent) so as to be marketable. The produced water or produced water/solids mixtures, discharged at this point, contain too much oil to be disposed of into a water body. The object of processing up to this point was to produce marketable products (clean oil and dry gas). In contrast, the next stages of treatment are necessary to remove sufficient oil from the produced water so that it may be discharged. These treatment operations do not significantly increase the quality or quantity of the saleable product but they do decrease the impact of these waters on the environment.

Produced waters from the last stage of processing typically contain several hundred to perhaps a thousand or more parts per million of oil. Two methods of disposal are treatment and discharge to surface (salt) waters or injection into a suitable

FIGURE III-6
TYPICAL VERTICAL HEATER-TREATER


GAS OUT
GAS OUTLET
EMULSION INLET
GAS SEPARATION
OIL OUTLET
HEAT EXCHANGER
FILTER SECTION
OIL SETTLING
WATER LEG
WATER SECTION
FIRE TUBE
OIL OUT
WATER OUT
EMULSION IN
DRAIN

Source:3

subsurface formation in the earth. Some of the same operations used to facilitate separation for processing (chemical addition and retention) are used to treat produced water. Other methods of treatment include separation by gas flotation and/or filtration.

EXISTING PRODUCTION PLATFORMS

Distribution of Platforms

At present, the majority of offshore oil and gas production occurs in the Gulf of Mexico (primarily Louisiana and Texas), and off the coast of California. Exploration and development have been underway in other offshore areas, (e.g., Atlantic coast, other Gulf states, Gulf of Alaska, Norton Sound, Bering Sea, and Beaufort Sea), but as yet no significant production is occurring at these sites.

Existing offshore production platforms are located within either federal or state lease tracts. Federal lease tracts encompass all waters that are not under state jurisdiction. Most states' jurisdictions over the leasing of offshore tracts extend three miles from their mainland coasts, with the following exceptions: Texas and Florida have jurisdiction over areas up to 3 leagues (9 nautical miles, or 10.4 statute miles) away from their shores. California's three mile limit is extended from all offshore islands, as well as its mainland coast. Alaska is currently negotiating with the federal government for jurisdiction over a three mile limit from its offshore islands in the Beaufort Sea.

Table III-1 presents a summary of the production platforms and producing wells that are operating in federal and state offshore waters. The inventory is based on information from

TABLE III-1

SUMMARY OF EXISTING OFFSHORE PRODUCTION PLATFORMS AND PRODUCING WELLS

	Federal Waters			State Waters		
Area	Production Platforms	Producing Wells	Reporting Date	Production Platforms	Producing Wells	Reporting Date
Alaska	0	0	9/82	0	0	12/82
Atlantic	0		9/82	0	0	
California	14	286	1/84	16	1731	1/84
Gulf of Mexico	2863	6534	9/82			
Alabama				3	0	12/82
Florida				0	0	12/83
Louisiana				800	2283	8/84
Mississippi				0	0	12/82
Texas				200	166	8/84
TOTALS	2877	6820		1019	4180	

Source: 252

the U.S. Mineral Management Service (MMS), Alaska Oil and Gas Commission, California Division of Oil and Gas, other state regulatory agencies, the American Petroleum Institute, and the Oil and Gas Journal. As of September 1982, there were 2877 and 1019 offshore production platforms operating in federal and state waters, respectively; with the vast majority located in the Gulf of Mexico.

Interpretation of Platform Data

As can be seen from Table III-1, the total number of existing offshore production platforms in federal and state waters combined was found to be 3896. The Federal waters portion of the platform count may be somewhat overstated. This is because the count is based on the MMS platform inspection system which may include structures other than production platforms in its count. In addition, certain factors should be carefully considered in using and interpreting Table III-1.

The various statistical sources use different procedures in counting offshore structures. Various types of structures such as production platforms, well protectors, drilling platforms, and auxiliary structures may in some cases appear grouped in statistics as "platforms." To the extent possible, only production platforms have been selected for inclusion here.

In addition, well types include producing wells, dry holes, shut-in wells, injection wells, and field drainage wells. In some cases, counts may group together several categories. To the extent possible, only producing wells have been counted.

It was impossible to determine to what extent old shut-in platforms were included in the Gulf of Mexico inventories. Possibly up to 10 percent of the MMS file counts for the Gulf of Mexico platforms may be nonproducing platforms. No adjustments to the inventory were made to account for shut-in platforms.

Finally, many of the platforms represented in the Texas and Louisiana counts are older platforms with few wells whereas the California platforms are newer, multiple well facilities. Also, it should be noted that existing platforms located in Alaska's Cook Inlet, which account for much of the production off the coast of Alaska, have not been included in Table III-1 since they are classified in the coastal subcategory. Thus, care must be used in interpreting aggregate platform counts.

Present Oil and Gas Production

Table III-2 shows the quantity of oil and gas produced by offshore platforms in the United States for the years 1970 through 1982. In 1982, offshore oil production amounted to approximately one million barrels per day, which was nearly 15 percent of the U.S. total. In addition, offshore gas production in 1982 was about 12,820 million cubic feet per day or 25 percent of the U.S. total. The wellhead value of offshore production for 1982 was $11.6 billion and $11.4 billion for oil and gas, respectively.

FUTURE PRODUCTION PLATFORMS

Projections of industry drilling and production activities up to the year 2000 were formulated by the Agency during the development of proposed effluent limitations guidelines and new source performance standards in order to assess the cost of such regulations. [252] Model facilities were defined to account for the diversity of geographic location, platform size, and production type encountered in offshore areas. A total of 31 model projects were designated to characterize the range of platform

TABLE III-2

QUANTITY AND VALUE OF OIL AND GAS PRODUCED

OFFSHORE IN THE UNITED STATES: 1970-1982

Year	Crude Oil and Condensate Production (million bbls/day)	Percent of Total U.S. Production	Value at Wellhead (billions of dollars)	Natural Gas Production (million cu ft/day)	Percent of Total U.S. Production	Value at Wellhead (billions of dollars)
1970	1.6	16.4	1.8	8,817	14.7	0.6
1971	1.7	17.8	2.0	10,276	16.7	0.7
1972	1.7	17.6	2.0	10,266	16.7	0.7
1973	1.6	17.2	2.2	10,891	17.6	0.9
1974	1.5	17.0	3.7	11,588	19.6	1.3
1975	1.4	16.3	3.8	11,664	21.2	1.9
1976	1.3	15.5	3.8	11,739	21.5	2.5
1977	1.2	14.4	3.7	12,438	22.7	3.6
1978	1.1	13.0	3.7	13,984	25.6	4.6
1979	1.1	12.5	4.9	14,852	26.5	6.4
1980	1.0	12.0	7.9	14,703	26.3	8.4
1981	1.0	12.1	12.0	15,117	27.3	10.9
1982	1.1	14.7	11.6	12,820	25.3	11.4

Source: 252

types that could be installed through the year 2000. Model projects were selected to reflect the different sizes of existing and planned structures within four regions, the Atlantic, the Gulf of Mexico, the Pacific, and the coast of Alaska. For production platforms new installations were estimated based on DOE production projections and other regional data sources, and are summarized in Table III-3. A total of 833 new platforms are projected for the period 1986-2000 that would be subject to NSPS.

TABLE III-3

PROJECTION OF NEW SOURCE DISCHARGING PLATFORMS BY REGION

	GULF WELLSLOTS						PACIFIC WELLSLOTS			ALASKA			TOTAL	
YEAR	2x5	4	12	24	40	58	16	40	34	48-WELL GRAVEL ISLAND	BEAU-FORT. PLAT-FORM 48	BERING PLAT-FORM 48	DISCHARGING PLATFORMS	WELLS
1986	13	17	0	0	0	0	0	0	0	0	0	0	30	198
1987	12	17	12	11	2	0	1	3	0	0	0	0	58	682
1988	12	17	12	11	2	1	1	2	1	0	0	0	59	727
1989	12	16	12	11	2	1	1	1	0	0	0	0	56	662
1990	12	16	12	10	2	1	1	3	0	1	0	0	58	750
1991	10	17	11	10	2	1	1	2	0	0	0	0	54	651
1992	10	16	12	11	2	1	0	3	0	0	0	0	55	695
1993	10	16	12	11	2	1	1	3	0	0	0	0	56	708
1994	11	17	11	11	2	0	1	3	0	1	0	0	57	702
1995	12	14	12	10	2	1	1	3	0	0	0	0	55	702
1996	12	16	13	11	1	1	0	2	0	1	0	1	58	740
1997	9	17	12	10	2	1	1	3	1	0	0	0	56	712
1998	12	14	13	11	2	0	1	2	0	1	1	1	58	767
1999	12	16	14	10	2	1	1	3	0	1	1	0	61	810
2000	11	17	13	11	2	1	1	3	0	1	1	1	62	852
TOTAL	170	243	171	149	27	11	12	36	2	6	3	3	833	-
TOTAL	1,700	972	1,710	2,682	864	550	156	1,188	56	240	120	120	-	10,358

Source: 252

PROCESS WASTE SOURCES

Sixteen potential waste sources have been identified with the drilling and production activities of the offshore oil and gas industry; some of which occur in both stages. The following is a listing of potential waste sources.

Drilling fluids
Drill cuttings
Well treatment fluids
Produced water
Produced sand
Deck drainage
Sanitary wastes
Domestic wastes
Blowout preventer fluid
Desalination unit discharge
Fire control system test water
Non-contact cooling water
Boiler blowdown
Ballast and storage displacement water
Bilge water
Discharges from water flooding operations

Of these, drilling fluids, drill cuttings and produced waters contribute most of the quantity and chemical constituents of pollutants discharged by this industry. The remaining waste streams can be effectively controlled by:

- individual waste treatment with separate discharge,
- commingling with one of the above for treatment, and
- industry techniques that avoid contamination and allow for discharge of non-contaminated materials.

The following is a discussion of each process waste source and the type of waste which may result. Waste characteristics (flow and pollutant concentrations) for those waste streams that may require treatment is included in Section V.

Drilling Fluids

Drilling fluids, or muds, are suspensions of solids and dissolved materials in a base of water or oil that are used in rotary drilling operations to lubricate and cool the drill bit, carry cuttings from the hole to the surface, and maintain hydrostatic pressure downhole. In the early days of oil drilling, only water was used to remove cuttings. However, drilling procedures are far more sophisticated today. Well depths have increased, and complex drilling fluids are necessary for efficient, economical, and safe completion of the well drilling operation.

Drilling fluids can be water-based or oil-based. Oil-based drilling fluids are those in which oil, typically diesel, serves as the continuous phase with water as the dispersed phase. Such fluids contain blown asphalt and usually one to five percent water emulsified into the system with caustic soda or quicklime and an organic acid. Silicate, salt, and phosphate may also be present.

Oil-based muds are more costly and more toxic than water-based muds, and are normally used only for particularly demanding drilling conditions. However, the use of oil-based drilling fluids, or invert emulsion mud systems, has increased significantly over the past several years as a result of their advantages over water-based fluids in difficult drilling situations. These advantages include excellent thermal stability when drilling deep, high-temperature wells; lubricating characteristics which aid in drilling deviated wells offshore; and the ability to drill thick, water sensitive shales with few stock pipe or hole wash out problems. A primary concern when using conventional, diesel oil-based mud systems is their potential for adverse environmental impact. Mineral oil-based mud systems have recently been developed as less toxic alternatives.

In water-based muds, water is the suspending medium for solids and is the continuous phase, whether or not oil is present. Water-based muds are more commonly used offshore and were focused upon in this development document. Water-based drilling fluids are comprised of approximately 70 to 90 percent water by volume, with a variety of mud additives constituting the remaining portion.

Functions of Drilling Fluids. Drilling fluids are specifically formulated to meet the physical and chemical requirements of a particular well. Mud composition is affected by geographic location, well depth, and rock type, and is altered as well depth, geologic formations, and other conditions change. The number and nature of mud components varies by well, and several products may be used at any given time to control the properties of a mud system. The eight basic functions of a drilling fluid are as follows [62]:

1. Transport drill cuttings to the surface,
2. Suspend drill cuttings in the annulus when circulation is stopped,
3. Control subsurface pressure,
4. Cool and lubricate the bit and drill string,
5. Support the walls of the wellbore,
6. Help suspend the weight of the drill string and casing,
7. Deliver hydraulic energy upon the formation beneath the bit, and
8. Provide a suitable medium for running wireline logs.

Components of Drilling Fluids. Four basic components account for approximately 90 percent by weight of all materials consumed in drilling fluids, namely barite, clays, lignosulfonates, and lignites [31]. A recent survey conducted by the Agency found similar results for offshore drilling operations in the Gulf of Mexico [182]. The composition of these basic materials is discusssed in Section V. Other components include lime, caustic soda, soda ash, and a multitude of specialty additives. These additives are used to modify the characteristics of drilling muds as dictated by well requirements to control site specific drilling conditions. Table III-4 lists some of the common types and functions of materials used in drilling fluid systems.

Drill Cuttings

Drilling fluids circulate in the bore hole and move up the annular space between the drill string and the borehold to the surface, carrying drill cuttings with it. Cuttings are removed from the drilling fluid by a step-wise process which removes particles of decreasing size.

Upon reaching the surface, fluids and cuttings pass to the shale shaker, a vibrating screen that removes large particles from the fluid. Standard shaker screens generally remove particles larger than 440mm, and fine screen shakers using cloth finer than 30mm, remove particles down to approximately 120mm [163]. The fluid is then passed to the sand trap, a gravitational settling tank removing particles from approximately 74 to 210 mm, if shale shaker damage or shaker by-passing is a problem. A desilter, a hydrocyclone using centrifugal forces, can then be used to remove silt-sized particles (approximately 5 to 75mm). After removal, the cuttings are discharged anywhere from the rig near the water surface or below the surface of the sea. Processed drilling fluids return to the mud tanks for recirculation to the well.

TABLE III-4

FUNCTIONS OF SOME COMMON DRILLING MUD CHEMICAL ADDITIVES [254]

1. Alkalinity and pH Control: Caustic soda, sodium carbonate, sodium bicarbonate, and lime are commonly used to control the alkalinity of the drilling fluid and secondarily to control bacterial growth.

2. Bactericides: Paraformaldehyde, alkylamines, caustic soda, lime, and starch preservatives are typically used as bactericides to reduce the bacteria count in the mud system. Halogenated phenols are no longer permitted for OCS use.

3. Calcium Removers: Caustic soda, soda ash, sodium bicarbonate, and certain polyphosphates are added to control the calcium buildup which prevents proper functioning of drilling equipment.

4. Corrosion Inhibitors: Hydrated lime and amine salts are added to drilling fluids to reduce corrosion potential.

5. Defoamers: Aluminum stearate and sodium aryl sulfonate are commonly used and are designed to reduce foaming action that occurs particularly in brackish waters and saturated saltwater muds.

6. Emulsifiers: Ethyl hexanol, silicone compounds, modified lignosulfonates, and amionic and nomionic products are used as emulsifiers to create a homogeneous mixture of two liquids.

7. Filtrate Loss Reducers: Bentonite clays, a range of cellulose polymers such as sodium carboxymethyl cellulose (CMC) and hydroxyethyl cellulose (HEC), and pregelated starch are added to drilling fluid to prevent the invasion of the liquid phase into the formation.

8. Flocculants: Salt (or brine), hydrated lime, gypsum, and sodium tetraphosphate cause suspended colloids to group into "flocs" and settle out.

9. Foaming Agents: These products are designed to foam in the presence of water and allow air or gas drilling through formations producing water.

10. Lost Circulation Materials: Wood chips or fibers, mica, sawdust, leather, nut shells, cellophane, shredded rubber, fibrous mineral wool, and perlite are all used to plug pores in the well-bore wall and to reduce or stop fluid loss into the formation.

TABLE III-4 (CONTD)

FUNCTIONS OF SOME COMMON DRILLING MUD CHEMICAL ADDITIVES

11. Lubricants: Certain hydrocarbons, mineral and vegetable oils, graphite powder, and soaps are used as lubricants to reduce friction between the drill bit and the formation.

12. Shale Control Inhibitors: Gypsum, sodium silicate, polymers, limes, and salt reduce wall collapse caused by swelling or hydrous disintegration of shales.

13. Surface Active Agents (Surfactants): Emulsifiers, de-emulsifiers, and flocculants reduce the relationship between viscosity and solids concentration, vary the gel strength, and reduce the fluid's plastic viscosity.

14. Thinners: Lignosulfonates, tannins, and various polyphosphates are used as thinners since most of these also remove solids. Thinners act by deflocculating associated clay particles.

15. Weighting Materials: Products with high specific gravities, predominantly barite, calcite, ferrophosphate ores, siderite, and iron oxides (hematite), are used to increase drilling mud weight.

16. Petroleum Hydrocarbons: These products (diesel or mineral oil) may be added to mud systems for specialized purposes such as freeing a stuck pipe.

Solids removal system discharges consist of: drill cuttings, wash solution and drilling mud which is still adhering to the cuttings. Also, at a certain well on the Southern California outer continental shelf it was found that normal cuttings discharges from solids control equipment was comprised of 0-96% cuttings solids and 4% adhered drilling fluid [170]. However, data from a mid-Atlantic coast well placed these values at 40 percent drill cuttings and 60 percent drilling fluids [166]. These data suggest that the nature of the discharges may be well-specific.

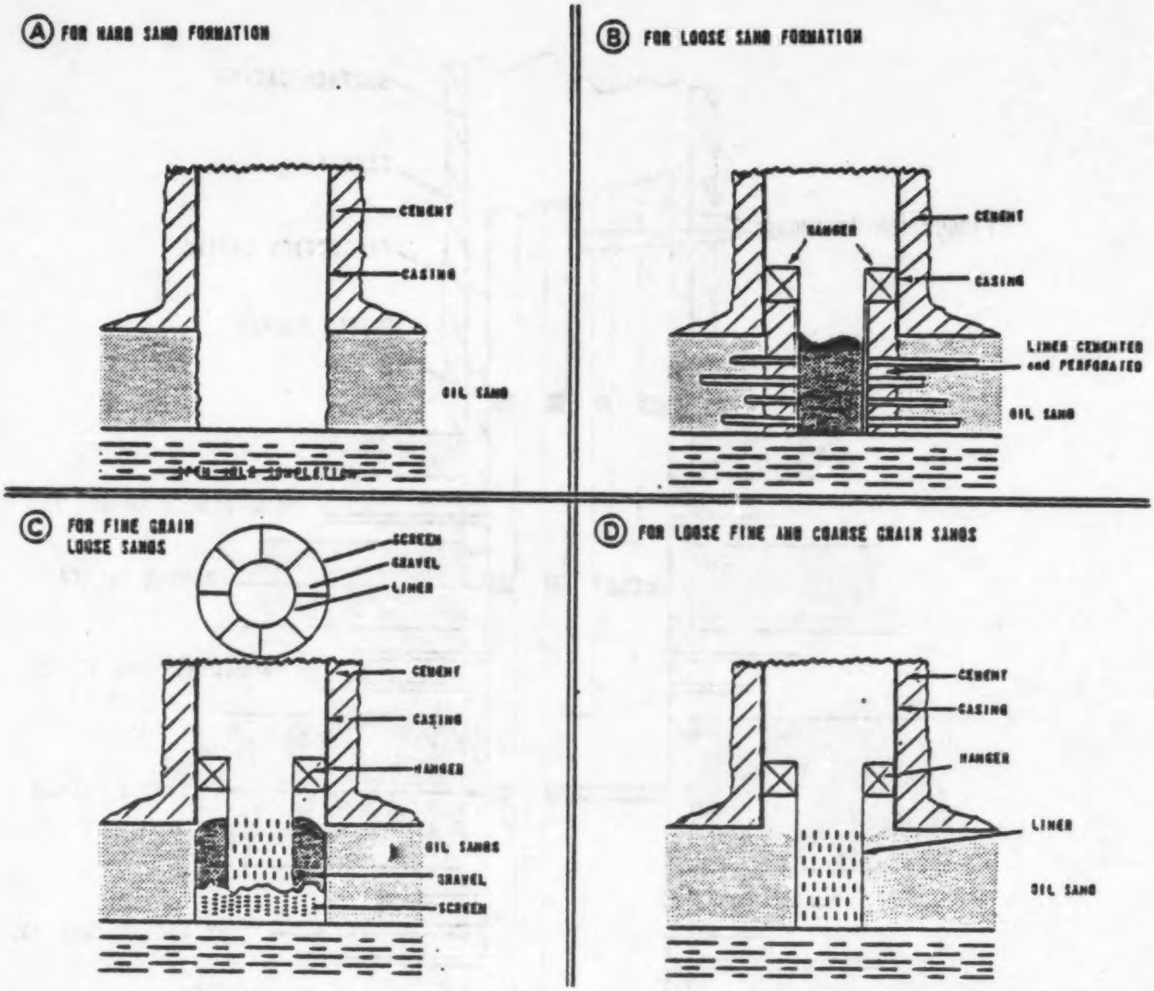
Well Treatment Fluids

Well treatment fluids are special-case fluids used in completing a well for oil and gas production, and in reworking a well and stimulating a hydrocarbon-bearing formation to increase or restore productivity.

After drilling is finished, well logging data are evaluated to determine the productivity of the well. If the well is not capable of producing commercial quantities of oil or gas (dry hole), the well is plugged. If commercial quantities of oil or gas are found then the well is "completed."

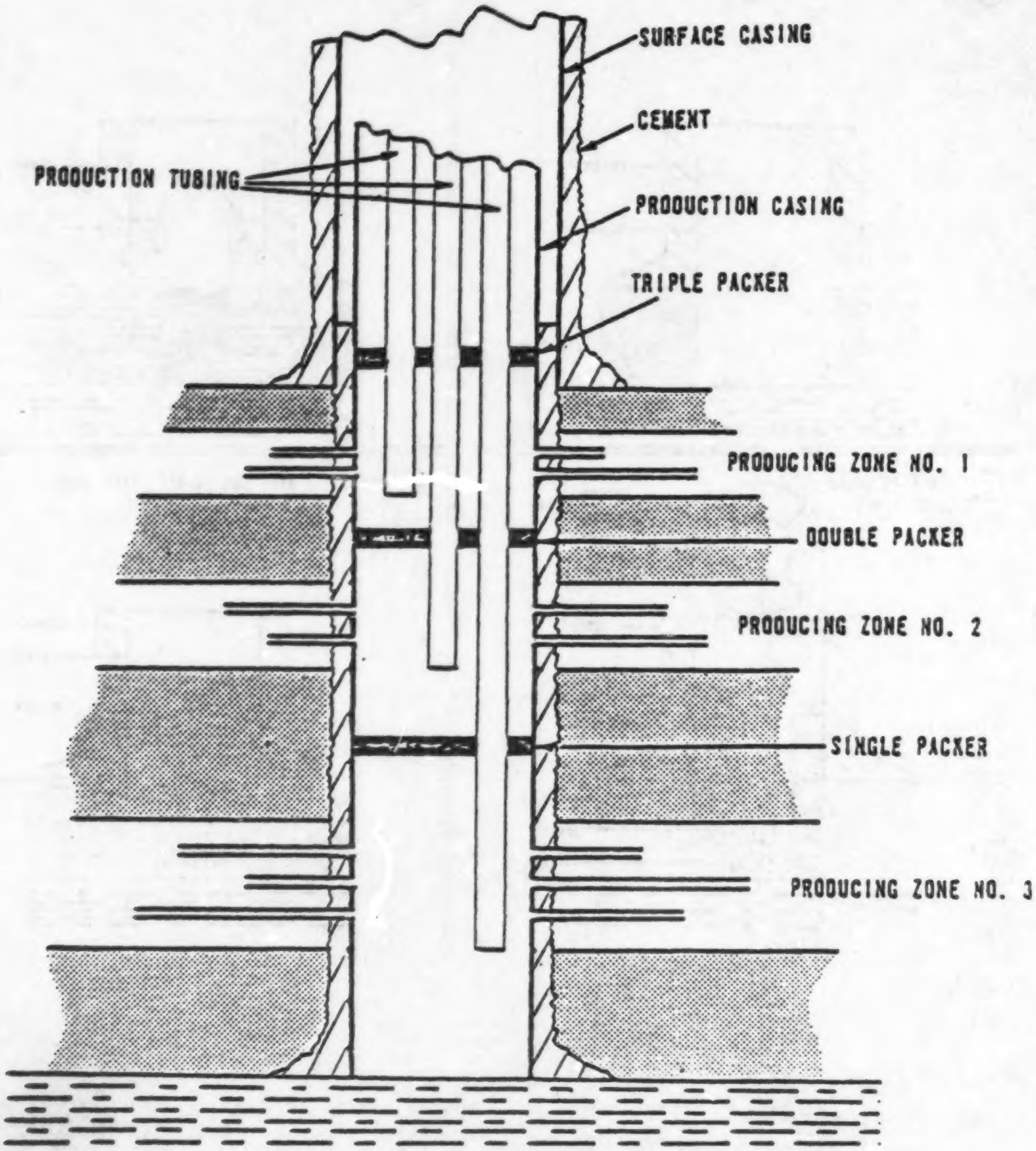
Completion. Well completion occurs if a commercial-level hydrocarbon reserve is discovered. Completion of a well involves setting and cementing the casing, perforating the casing and surrounding cement to provide a passage for oil and gas from the formation into the well bore, installing production tubing, and packing the well. The methods of completion of a well are governed by the nature of the reservoir. Various methods of completion are illustrated in Figure III-7. Sometimes a well penetrates more than one producing stratum requiring an additional completion method illustrated in Figure III-8.

FIGURE III-7
TYPICAL COMPLETION METHODS


Ⓐ FOR HARD SAND FORMATION
CEMENT
CASING
OIL SAND
OPEN HOLE COMPLETION
Ⓑ FOR LOOSE SAND FORMATION
HANGER
CEMENT
CASING
LINER CEMENTED and PERFORATED
OIL SAND
Ⓒ FOR FINE GRAIN LOOSE SANDS
SCREEN
GRAVEL
LINER
CEMENT
CASING
HANGER
OIL SANDS
GRAVEL
SCREEN
Ⓓ FOR LOOSE FINE AND COARSE GRAIN SANDS
CEMENT
CASING
HANGER
LINER
OIL SAND

Source: 184

FIGURE III-8
MULTIPLE WELL COMPLETION


SURFACE CASING
CEMENT
PRODUCTION TUBING
PRODUCTION CASING
TRIPLE PACKER
PRODUCING ZONE NO. 1
DOUBLE PACKER
PRODUCING ZONE NO. 2
SINGLE PACKER
PRODUCING ZONE NO. 3

Source: 184

The function of completion fluids is to seal off or temporarily plug the face of the producing formation in the bore hole so that, during completion operations, fluids and solids are not lost into the producing formation thereby reducing its productivity.

Ideally, sealing is accomplished by depositing a thin film of solids over the surface of the producing formation without forcing solids into the formation. The solids which are deposited on the formation surface are called "bridging agents" and temporarily close the formation pores. Various types of oil soluble or acid soluble bridging agents are available. The bridging agent is dissolved (by oil, acid, or brine) when the completion operation is finished so that oil or gas may be produced.

It is important that maximum permeability of the producing formation be retained. A non-damaging completion fluid is one that causes a minimum of permanent plugging of the formation pores. Composition of completion fluids varies greatly and is site specific depending on the nature of the producing formations.

The production zone is a porous rock formation containing the hydrocarbons, either oil or gas, and can be damaged by mud solids and water contained in drilling fluids. To avoid this, and to maximize production rate, a special low-solids completion fluid may be used to drill through the production zone.

Well Casing and Cementing. In order to protect the well from being penetrated by aquifers, it is necessary to install a casing in the bore hole. The casing is usually installed in stages as the drilling progresses, each stage being a successively smaller diameter. The casings are cemented in place after each installation.

The first string of casing and the largest diameter is called the surface string and may vary from about 60 meters (200 ft) to about 450 meters (1500 ft) depending on local conditions. After placing the surface string and cementing it in, drilling is resumed with a smaller drill bit than the original.

The second string of casing called the intermediate or "salt" string is generally run to a depth sufficient to seal off the salt and anhydrite formations and may reach a depth of 1500 meters (5000 ft.) or more. After cementing in, drilling is resumed. The final string of casing, the oil string, usually extends through the surface and salt strings to the producing zones. Various devices are attached to the outside of the casing pipe to keep it centered in the bore hole and to remove caked drilling mud from the hole walls.

Another string of pipe is placed in the well called the tubing through which the production oil flows. This tubing size is much smaller than the casing (typically 1.5 inch to 4.5 inch diameter). The tubing is suspended from the well head and reaches to the producing zone or almost the bottom of the well. Where multiple producing zones are penetrated, separate tubes, isolated by packers, may be installed for each zone in the same casing, see Figure III-8.

The cementing operation is normally performed by a cementing service company with the assistance of the drilling crew. Cement slurry is mixed on site and is pumped through a special valve at the well head through the casing to the bottom and up the annular space between the bore hole wall and the outside of the casing to the surface. A top plug is pushed through the casing and annular space by the cement, which in turn is moved out of the casing with a displacement fluid. The cement is allowed to harden and drilling is resumed.

Most wells are cemented with an ordinary Portland cement slurry. The amount of cement per well will depend on well depth and the volume of the annular space to be filled. Additives may be used to compensate for temperature and salt water conditions specific to the site. Loss of cement to the environment during this operation is relatively small.

Packing. Packer fluids are typically mixtures of a polymer viscosifier, a corrosion inhibitor and a high-concentration salt solution. This mixture remains between the well casing and the flow tubing, just above the production zone (hydrocarbon reservoir) during well completion and production [53]. These fluids are returned to the surface during well workover.

Workover. Sometimes a well, once considered nonproductive, is unplugged and completed if economic shifts in the industry change the profitability of the oil or gas yield. The "reopening" of a well is known as a "workover." The term also applies to remedial work on a producing well to increase productivity. Workover fluids are used to allow safe maintenance and repair procedures so that recovery of hydrocarbons from the producing reservoir can be accomplished. Workover operations can include "stimulation" and "killing" of the well.

Stimulation - When the producing zone of a well has such a low permeability that hydrocarbons cannot readily flow into the well, stimulation may be necessary. When this condition is encountered, it becomes necessary to increase the permeability of the oil bearing stratum to increase the production rate of crude oil. "Well stimulation" encompasses three basic methods: explosives, hydraulic fracturing and acid treatment (also called etching). Choice of method for well stimulation depends on the characteristics of the bearing formation with respect to the type of rock, characteristics of the crude, the relative amounts of water and natural gas and other geological factors.

Use of explosives to stimulate well flow began in the 1800's; however, development of hydraulic fracturing and acid treatment in the 1940's practically eliminated the use of explosive stimulation. Recently it has been found that some formations do not respond well to the fracture and acid technologies and that many older, explosively simulated, wells are still in commercial production after the fractured and acidized wells have been shut down. These findings, coupled with improved safer explosives and application techniques, have renewed interest in stimulation of wells by explosives [184].

There are two basic methods of using explosives in well stimulation. The first method is to detonate at the producing zone level in the bore hole, thereby effectively increasing the well hole size. The second method involves injection of the explosive into fissures and voids away from the bore hole, thereby increasing the area of influence of the explosive fracture. In either case, the resultant broken rock prevents the fractures from closing.

Hydraulic fracturing is achieved by pumping fluids at high pressure, frequently exceeding 10,000 psi, into the bore hole, literally splitting the rock. Proper fracturing accomplishes the following:

(1) creates reservoir fractures thereby improving the flow of oil to the well;
(2) improves the ultimate oil recovery by extending the flow paths; and
(3) aids in the enhanced oil recovery operation.

Since, over a period of time, the fractures tend to close up, it is necessary to introduce materials into the fissures to keep them open. Typical materials used include sand, ground walnut shells, aluminum spheres, glass beads, and similar inert particles. These materials, known as "propping agents", are carried into the fractures by the fracturing fluid.

Acid stimulation of a well is achieved by pumping an acid solution down the well and forcing the solution into the producing formation. The primary purpose of acid treatment is to dissolve the rock, thereby enlarging the openings allowing increased oil flow. The formations most often acidized are those of limestone or dolomite.

The acid medium employed must have some specific characteristics such as:

(1) the reaction products must be water soluble;
(2) the acid must be safe to handle; and
(3) since large volumes are used, it must be fairly inexpensive.

The most common type of acid treatment also results in the fracture of the stratum with the acid acting as both the fracturing and dissolving medium. Another type of acidizing known as "matrix acidizing" consists of pumping the acid at a pressure low enough to avoid fracturing the formation.

Specialized chemicals have been developed for well stimulation. For example, fracture fluids must have viscosity properties to permit proper placement of the proppant. Acid treatment fluids must be inhibited to minimize acid attack on the well casing and piping. Also, surfactants, sequestering agents, gelling agents and suspending agents may be required. The choice of material is determined by field conditions and the experience of the well stimulation contractor. Typical chemicals used in well stimulation are polymers, acid salts, acetic acid and acid/oil emulsions.

The potential for release to the environment of the well stimulating chemicals is, by nature of the procedure, very limited. Most of the materials, in the case of acidizing, react with the rock and are destroyed. Those that are not destroyed either remain in the formation or are flushed out and diluted with the produced fluids.

Killing - When a new well is being completed, or when it is necessary to pull tubing during workover operations, "killing" a well is normally accomplished. A column of drilling mud, oil, water, or other liquid of sufficient weight is introduced into the well to control the down hole pressures. When the work is completed, the liquid used to kill the well must be removed so that the well will flow again. If mud is used, the initial flow of oil from the well will be contaminated with the mud. If oil is used, it is recovered because of its value, either by collecting it directly or by moving it through the production system. If the killing fluid is mud, it will be collected for reuse or discharged. If water is used, it will be moved through the production and treatment systems and disposed of.

Salts are used in low-solids fluids to inhibit clay swelling and gellation, and to obtain the necessary fluid density without solid weighting materials. $NaCl$ and KCl are used for fluid densities to 1.2 kg/L (10 lb/gal), $CaCl_2$ with or without $NaCl$ is used for densities to 1.38 kg/L (11.5 lb/gal), and $CaBr_2$ and $ZnBr_2$ can be used in combination for densities up to about 2.16 kg/L (18 lb/gal).

When placed opposite or circulated past a permeable formation, drilling mud will lose some of its liquid phase into that formation. Mud solids will deposit on the walls of the hole and form a filter cake, ideally about 1/32-in. thick. The liquid lost to the formation is the filtrate, and the relative rate at which it is lost is the filtration rate [62].

Control of viscosity and filtration rate require special consideration in low-solids systems. Organic polymers, such as hydroxyethyl cellulose and xanthan gum, are used for viscosity and to aid in filtration control. Ground calcium carbonate may then be necessary to start filter cake formation in permeable sand (subsequent acidification will dissolve the calcium carbonate enough to disintegrate the filter cake).

Other special additives are also necessary in low-solids systems. Corrosion inhibitors, such as amine derivations, are used in salt systems to reduce damage to casings. Inhibitors also act as biostats to prevent microbial degradation of polymers. A biocide, such as paraformaldehyde, may still be necessary. A buffer, usually magnesium oxide, may be required to stabilize pH and maintain polymers in an effective form. Defoamers, such as alkyl alcohols, and sulfonated vegetable oils, are used to avoid air and gas entrapment.

High solids fluids are also used in completion and workover. They may contain the same materials as those used for drilling except that they may be freshly formulated to avoid fine drilled cuttings that accumulate in the used drilling fluid. Again, calcium carbonate is often used as an acid-soluble weighting material for densities up to 1.5 kg/L (12.5 lb/gal). Iron carbonate has been used for densities up to 1.68 kg/L (14 lb/gal).

Produced Water

Produced water (also known as production water or produced brine) is the total water discharged from the oil and gas extraction process. It is comprised of the formation water, which has been brought to the surface with the oil and gas, injection water (if used for secondary oil recovery and has broken through into the oil formation), and various chemicals added during the oil/water separation process. Produced water contains dissolved, emulsified and particular crude oil constituents, natural and added salts, organic chemicals, solids and trace metals. Produced water constitutes the major waste stream from offshore oil and gas production activities.

Formation Water. Formation water, not to be confused with produced water, is found in the rock formation, along with crude oil and gas, before it is brought to the surface. It is difficult to accurately describe its chemical composition because formation water is under pressure and in equilibrium with crude oil and gas in the formation.

Formation waters may be classified as meteoric, connate or mixed. Meteoric water has fallen as rain, percolated through underground bedding planes and permeable layers, and can contain carbonates, bicarbonates, and sulfates. Connate waters, or seawater in which marine sediments were originally deposited, are characterized by an abundance of chlorides, particularly sodium chloride ($NaCl$), and have concentrations of dissolved solids many times greater than that of common seawater. Mixed waters are characterized by both a high chloride and sulfate-carbonate-bicarbonate content, which suggests a multiple origin.

Formation water can range from 2 to 98 percent of oil production over the life of a well; the proportion of co-produced water generally increases with the age of the well. In mature wells, 60 percent or more of the produced fluid is water from the hydrocarbon-bearing formation. However, generalizations about water production cannot reliably be made because water content varies by formation. Wells have been noted with high water content throughout their lifespan; others have been found to contain little or no water; and still others have, initially yielded little water, with the water fraction generally increasing with well age. While there is no correlation between produced water and gas/oil production, a common field assumption is that over the life of an oil field, the gross volumes of oil and water produced are approximately equal.

Water Flooding. Many oil fields that have been produced to depletion and have become economically marginal may be restored to production with recoverable reserves substantially increased by secondary recovery methods. The most widely used secondary recovery method is water flooding. A grid pattern of wells is established, which usually requires downhole repairing of old wells and drilling of new wells. By injecting water into the reservoir at high rates, a front or wall of water moves horizontally from the injection wells toward the producing wells, building up the reservoir pressure and sweeping oil in a flood pattern. Water flooding can substantially improve oil recovery from reservoirs that have little or no remaining reservoir pressure. Treated seawater is typically used offshore for injection purposes. Treatment consists of filtration to remove solids that would plug the formation and deaeration. Dissolved oxygen is removed to protect the injection pipeline system from corrosion. A variety of chemicals can be added to water flooding systems, such as flocculants, scale inhibitors, and oxygen scavengers. Biocides are also used to prevent the growth of anaerobic sulfate-reducing bacteria, which can produce corrosive hydrogen sulfide in the injection system. Discharges to the marine environment from water flooding operations will include excess injection water and backwash from filtering systems.

Enhanced Oil Recovery. When an oil field is depleted by primary and secondary recovery methods (e.g., natural flow, artificial lift, waterflooding), as much as 50 percent of the original oil can remain in the formation. Enhanced oil recovery (EOR) processes have been developed to recover a portion of this remaining oil. The EOR processes can be divided into three general classes: thermal, chemical and miscible displacement.

Thermal - Thermal processes include steam stimulation, steam flooding and in situ combustion. Steam stimulation and flooding processes differ primarily in the number of wells involved in a field. Steam stimulation uses an injection-wait-pump cycle in a single well, whereas, the steam flooding process uses a continuous steam injection into a pattern of wells and continuous pumping from other wells within the same pattern. The in situ combustion process does not use any chemicals other than the oxygen required to maintain the fire.

Chemical - Chemical EOR processes include surfactant-polymer injection, polymer flooding and caustic flooding. In the first process a slug of surfactant solution is pumped down the injection well followed by a slug of polymer solution to act as a drive fluid. The surfactant "washes" the oil from the formation and the oil/surfactant emulsion is pushed toward the producing well by the polymer solution. In polymer flooding, a polymer solution is pumped continuously down the injection well to act as both a displacing compound and a drive fluid. Surfactant and polymer injection may require extensive treatment of the water used in solution make-up before the surfactant or polymer is added. Caustic flooding is used to drive oil through a formation toward producing wells. The caustic is delivered to the injection wells via a manifold system; the injection head is similar to that used in steam flooding.

Miscible displacement - These EOR processes use an injected slug of hydrocarbon (e.g., kerosene) or gas (e.g., carbon dioxide) followed by an immiscible slug (e.g., water). The miscible slug dissolves crude oil from the formation and immiscible slug drives the lower viscosity solution toward the producing well. The injection head and manifold system are similar to those used for steam flooding.

Produced Sand

Produced sands are sand and clay solids which are brought to the surface and removed from crude oil and produced water. Low volumes of fine sands may be drained into drums on deck or are carried through the oily water treatment system and appear as suspended solids in the produced water effluent or settle out in treatment vessels. If sand volumes are larger and sand particles coarser, the solids are removed in cyclone separators, thereby producing a solid phase waste. The sand which drops out in these separators is generally contaminated with crude oil (oil production) or condensate (gas production) and requires washing to recover the oil. The sand is washed with straight water, water combined with detergent, or solvents. The oily water is directed to the produced water treatment system or a separate oily water separator and becomes part of the produced water discharge, following oil separation. The clean sand is discharged overboard, or hauled to shore for land disposal. In some locations (a number of Gulf of Mexico and Cook Inlet platforms) the produced sands are piped to shore with produced water, separated and disposed of on land.

Deck Drainage

Deck drainage includes waste resulting from platform washings, deck washings, rainwater and runoff from curbs, gutters and drains. Deck drainage may also include spills from work areas and drip pans, and detergents used in deck and equipment washing procedures.

Oil is the primary pollutant in deck drainage. However, during drilling operations, spillage of drilling fluids can occur, and may end up as deck drainage. Acids (hydrochloric, hydrofluoric, and various organic acids) used during workover operations may also contribute to deck drainage, but generally these are neutralized by deck wastes and/or brines prior to disposal.

A typical platform-supported rig is equipped with pans to collect deck and drilling floor drainage. The drainage is gravity separated into waste material and liquid effluent. Waste materials are recovered in a sump tank, then treated prior to disposal, used in the drilling mud system, or transported to shore. The liquid effluent, consisting primarily of washwater and rain water, is dumped overboard.

Sanitary Wastes

The sanitary wastes from offshore oil and gas facilities are composed of human body wastes. The volume and concentration of these wastes vary widely with time, occupancy, platform characteristics, and operational situation. Usually the toilets are flushed with brackish water or sea water. Due to the compact nature of the facilities the wastes have less dilution water than common municipal wastes. This results in greater waste concentrations. Some platforms combine sanitary and domestic wastewaters for treatment; others maintain sanitary wastes separate for chemical or physical treatment by an approved marine sanitation device.

Domestic Wastes

Domestic wastes (gray water) originate from sinks, showers laundries, food preparation areas and galleys on the larger facilities. Domestic wastes may also include solid materials (paper, boxes, etc.) which are combustible.

Miscellaneous

Blowout Preventer (BOP) Fluid. An oil (vegetable or mineral) or antifreeze solution (glycol) is used as a hydraulic fluid in BOP stacks during drilling of a well. The blowout preventer may be located on the sea floor, and is designed to contain pressures in the well that cannot be contained by the drilling mud. Small quantities of BOP fluid are discharged periodically to the sea floor during testing of the blowout preventer device.

Desalination Unit Discharge. This is the residual high-concentration brine discharged from distillation or reverse-osmosis units used for producing potable water and high quality process water offshore. It has a similar chemical composition and ratio of major ions as sea water, but with higher concentrations. This waste is discharged directly to the sea as a separate waste stream.

Fire Control System Test Water. Sea water, which may be treated with a biocide, is discharged periodically, during tests of fire control systems, directly to the sea as a separate waste stream.

Non-Contact Cooling Water. Non-contact, once-through water is used to cool crude oil, produced water, power generators and various pieces of machinery. Biocodes can be used to control biofouling in heat exchanger units. Noncontact cooling waters are separately maintained and discharged directly.

Ballast and Storage Displacement Water. Two types of ballast water are found in offshore producing areas (tanker & platform ballast). Tanker ballast water comprises sea water or fresh water from the region where ballast was pumped into the vessel. It may be contaminated with crude oil (or possibly some other cargo such as fuel oil) if the vessel does not have segregated cargo and ballast tanks.

Unlike tanker ballast water, which may have had multiple sources and which may contain added contaminants, platform stabilization (ballast) water is taken on from the waters adjacent to the platform and will, at worst, be contaminated with stored crude oil and platform oily slop water. Newly designed and constructed floating storage platforms use permanent ballast tanks which become contaminated with oil only in emergency situations when excess ballast must be taken on. Oily water can be treated through an oil/water separation process prior to discharge.

Storage displacement water from floating or semi-submersible offshore crude oil structures is mainly composed of sea water. Much of its volume can usually be discharged directly without treatment, since little mixing occurs with the oil floating on top of the water. The water which is in contact with the oil can receive a small amount of dissolved aromatic constituents through molecular diffusion at the oil-water interface. Paraffinic compounds have low solubilities in water and will not migrate into water solution to any appreciable degree. Crude oil constituents will not be significantly dispersed in particulate form into the water below, except in unusual circumstances such as very rough seas, because the oil-water interface is always maintained. The interface water is usually treated through an oily water separator system before discharge.

Bilge Water. Bilge water, which seeps into all floating vessels, is a minor waste for floating platforms. This sea water becomes contaminated with oil and grease and with solids such as rust where it collects at low points in vessels. This bilge water is usually directed to the oily water separator system used for the treatment of ballast water or produced water, or is discharged intermittently.

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IV. INDUSTRY SUBCATEGORIZATION

In many industries, factors which affect the ability of facilities to achieve technology-based limitations vary among groups of facilities within the industry. In such cases, EPA will establish different effluent limitations, guidelines, or standards for the various groups of facilities (i.e., subcategories). Essentially, subcategorization allows the Agency to more precisely tailor the requirements of technology-based limitations to the capacity of a diverse industry.

The oil and gas extraction point source category currently includes five subcategories: offshore, onshore, coastal, agricultural and wildlife water use, and stripper (40 CFR Part 435). This document covers only the offshore subcateogry. This subcategory is applicable to those facilities engaged in field exploration, drilling, well production, and well treatment in the oil and gas extraction industry which are located in waters that are seaward of the inner boundary of the territorial seas as defined in Section 502 of the Act.

The studies in support of previously proposed NSPS and BAT and final BPT regulations for the oil and gas extraction industry concluded that three major factors, geographic location, type of facility, and wastewater disposition, are the bases for subcategorization of this industry (41 FR 44945, 44 FR 22069).

In developing proposed NSPS, BAT, and BCT regulations for the offshore segment of this industry, EPA evaluated characteristics of wells, platform waste effluents, available treatment technologies, and platform operations to determine if it was appropriate to modify the BPT subcategorization scheme. EPA found no basis upon which to change the existing subcategorization for the offshore segment. The Agency concluded that the exsiting single subcategory for the offshore segment was also appropriate for proposed NSPS, BAT and BCT regulations. It should be noted that while the Agency determined that it was not necessary to change the existing offshore subcategorization, the proposed NSPS includes different produced water standards based on the type of operation and location of the facility.

V. WASTE CHARACTERISTICS

INTRODUCTION

This section describes the characteristics of wastes generated as a result of offshore oil and gas exploration, development and production activities. Wastestreams from these activities are organized into the following functional groups to facilitate relating process source to effluent characteristics:

Drilling fluids
Drill cuttings
Well treatment fluids
Produced water
Produced sand
Deck drainage
Sanitary wastes
Domestic wastes

IDENTIFICATION AND DESCRIPTION OF WASTESTREAMS

Drilling Fluids

A survey was conducted by the Agency of drilling muds used in recently completed wells in the Gulf of Mexico [182]. Its purpose was to obtain an accurate estimate of the types and quantities of mud components used in current practice. Chemical inventories of base components and specialty additives used downhole were collected for 74 exploratory and development wells drilled offshore since 1981. These wells were representative of drilling activities in 55 lease areas throughout Louisiana state waters, Texas state waters, and federal OCS waters.

Survey findings indicate that four kinds of material, excluding water, account for about 90 percent, by weight, of all components used, namely barite, clays, lignosulfonates, and lignites. These four materials are discussed below.

Barite. Barite, also known as barytes or heavy spar, is a heavy, soft, and chemically inert mineral. Pure barite contains 58.8 percent barium (Ba) and 41.2 percent sulfate (SO_4). However, commercial forms can run as low as 92 percent $BaSO_4$ and contain such impurities as silica, iron oxide, limestone, and dolomite, as well as various trace metals.

Nearly all barite consumed in the U.S. is used as a weighting agent in drilling muds. Offshore wells, which on average are deeper and have higher subsurface pressures than onshore wells, account for a disproportionately high percentage of total consumption.

Barite is a ubiquitous mineral because barium and sulfur are common in the crust of the earth, being 16th and 14th in abundance, respectively, and because $BaSO_4$ is very insoluble. It tends to form a fine precipitate and is found in a range of grain sizes and textures.

Deposits of barite are classified into three types: (1) vein and cavity-filling deposits, (2) bedded deposits, and (3) residual deposits. Residual deposits are typically mined in open pits after removal of overburden. Bedded and vein deposits may be mined by open pit or underground methods depending on local conditions. Following extraction, most ore is beneficiated at the extraction site, usually by rigging or flotation. (Some deposits are pure enough that beneficiation is unnecessary.) The purified barite is then shipped to a processing plant to be crushed and ground.

Processed barite, which is frequently packed in hundred-pound bags, is more expensive to handle and transport than uncrushed ore, which can be dumped into open freight hoppers.

Consequently barite is usually shipped unground from mine to market before being processed. The major market for barite is petroleum drilling, an industry that accounted for 97 percent of domestic sales in 1981. Barite is also a raw material of chemical manufacturing, a filler in paint and in plastic and rubber products, and an additive to paper and glass.

The United States is the world's single largest producer of barite by a wide margin, outputting 2.0 million tons in 1982. (China was second with 0.8 million tons.) With approximately 87 percent of the U.S. output, Nevada was the leading barite-producing state. Missouri was second with approximately 6 percent of the total.

The demand for drilling mud grade barite is so great that the U.S. imports approximately as much crude ore as it mines domestically. In recent years, China has become the major source of U.S. imports, followed by Peru, Chile, and Morocco. From 1978 to 1980 these four countries supplied 30 percent of the crude barite consumed in the U.S. and accounted for 69 percent of all barite imports.

Very few trace metal analyses have been performed on barite sources. Available data, which come entirely from Canada and the U.S., are summarized in Tables V-1 and V-2 [164]. These data indicate that bedded deposits generally contain mercury and cadmium in quantities equal to or lower than the averages for ocean sediments. Vein and residual deposits show a much wider range than bedded sources: some have trace metal levels below ocean sediment and crustal averages, but others contain mercury, cadmium and zinc in quantities on the order of 100 times greater.

TABLE V-1

ANALYSIS OF TRACE ELEMENTS IN BARITE SAMPLES [164]

Source	Trace Element Concentration mg/Kg								
	Fe	Pb	Zn	Hg	As	Cd	Cd	Ni	Cu	Co
LITERATURE VALUES:										
Vein deposits:	8-22,000	4-1220	10-4100	0.06-14	7*	2-26	<0.2-19	19**	2-97	not detected
Bedded deposits:	100-3000	<10	<200***	0.06-0.19	<500***	1-11	<50***	<5-5	3-20	<5-60
THIS STUDY:										
Vein deposits:	200-59,000	<2-3370	<.2-9020	0.8-28	0.008-170		0.6-32	15-41	0.6-560	0.1-9.2
Bedded deposits:	2500-6000	1-1.8	6-10	0.13-0.26	1.4-1.8		0.5-0.7	0.4-5.7	5.4-7.6	1-2.2
REFERENCE MATERIAL:										
Crust average:	50,000	15	65	0.1	2		0.2	80	45	23
Ocean sediment:	50,000	110	40	0.3	8		1	240	350	100

* - One Analysis

** - Mean of 83 Analyses

*** - Semiquantitative Emission Spectrographic Analysis

TABLE V-2

COMPARISON OF RESULTS OF SOLUBILITY EXPERIMENTS IN BARITE SAMPLES [164] TO SEA WATER CONCENTRATIONS

Source	Trace Metal Concentration g/kg[2]						
	Hg	Pb	Zn	Cd	Cu	Ni	As
Open Oceans[1]	0.3	1	<1	0.03	<2	1	1
Low Trace Metal Barite	<.01-0.14[3]	<1-1	<.1	<.1-1.4	<1-1.9	2-5	<.2
High Trace Metal Barite	<.01-.32[3]	50-200	50-200	0.4-5	1-4.3	6.6-10	<.2

1. From compilation by Hogdahl

2. Results are for 0.45 m filtered samples in μg/kg

3. With bentonite <.01-.01

Clays. Bentonite is the most widely used clay. Its crystalline structure causes bentonite to swell upon contact with water, and this gelling ability suspends solid material and aids in the removal of drill cuttings from the borehole. The sealing properties of bentonite are also well established, which enable them to form an impermeable filter cake on the wellbore wall. When highly concentrated brine (produced water) is encountered at great depths, the swelling properties of the bentonites are severely reduced, and attapulgite or sepiolite clays are substituted.

Lignosulfonates. Lignosulfonates, by-products of the pulp and paper industry, are considered the best all-purpose deflocculants for water-based drilling fluids, and serve to maintain the mud in a fluid state. Water is not generally used to thin barite-containing muds because this practice is generally self-defeating, therefore, chemical deflocculants are used.

Ferrochrome lignosulfonate is a widely used form of lignosulfonate. It performs over a wide alkaline pH range, is resistant to common mud contaminants, is temperature stable to approximately 177°C (350°F), and will function in high soluble salt concentrations. Chromium can represent up to three percent by weight of ferrochrome lignosulfonate; the mud aqueous fraction of used seawater ferrochrome lignosulfonate drilling fluid contains approximately 1 ppm chromium. Most of this chromium is in the less toxic trivalent form. Moreover, most of the chromium is bound to clay particles, further limiting its bioavailability and toxicity [165].

Lignites. Lignites are used as deflocculants, like lignosulfonates, but are substantially less soluble in seawater. Lignite products are used to thin freshwater muds, reduce drilling fluid loss to the formation, and aid in the control of mud gelation at elevated temperatures.

Other components, including lime, caustic soda, soda ash, and a multitude of specialty additives, are used as dictated by well requirements. The quantities of components used were found to vary considerably from well to well, but certain trends were observed. Wells in federal Outer Continental Shelf waters required, on average, more drilling muds and specialty additives than did wells in state waters. Also, exploratory wells required more drilling mud and specialty additives than did development wells. Average total mud consumption for the surveyed wells amounted to 3.1 million pounds per exploratory well and 0.8 million pounds per development well.

Volume. Drilling fluid discharges from offshore oil and gas operations originate from the mud tanks, are generally in bulk form, and occur intermittently during well drilling. High and low-volume bulk discharges of drilling fluids from the mud tanks usually number 20 to 30 during the drilling of a well. Low volume fluid discharges will occur several times during drilling, and are associated with maintaining solids level in fluids, cementing operations, and well completion activity. High volume bulk discharges occur a few times during the drilling period, when:

- drilling fluid must be removed to allow dilution with water,
- drilling fluid is being changed from one type to another,
- drilling fluid tanks are being emptied at the end of drilling operations.

High volume discharges generally occur several times per well during an offshore drilling operation for each drilling fluid system changeover. Each discharge lasts for 20 minutes to 3 hours at a rate of 250 to 700 bbl/hr or more, for a total volume of up to 2000 bbl or more. For instance, bulk mud discharges for dilution purposes from a semi-submersible rig in Lower Cook Inlet were at the rate of 720 bbl/hr (for a 17 minute period-maximum volume of 200 bbl), and occurred three times during the drilling of a well [163].

Table V-3 provides estimates of the drilling fluid discharge rates for a Gulf of Mexico well-drilling program. Discharge rates for wells in different geographical locations are summarized in Table V-4. Drilling fluid discharges for the Tanner Bank are only available on a barrel-per-hour basis. This could not be extended to a barrel-per-day average because drilling fluid discharge rates and periods vary with individual rig operation.

Table V-5 shows quantities of the basic drilling fluid components used in wells greater than 2,800m (9,000 ft) deep as a function of depth. An analysis of drilling fluid additive use based on data from ten wells in the Gulf of Mexico and the Mid-Atlantic Outer Continental Shelf showed a correlation between total usage and depth of well; a linear increase was noted from about 680 metric tons (750 tons) at 3,100m (10,000 ft) to about 1,225 metric tons (1,350 tons) at 5,000m (15,000 ft) and to 1,815 metric tons (2,000 tons) at 6,100m (20,000 ft).

A distinction should be made between the amount of material used and the amount of material discharged. Some drilling fluid is always lost to the geologic formations or left in the well annulus at the completion of drilling. Ayers, et al. [166] presented a materials balance estimate of drilling fluid components used in a Mid-Atlantic drilling operation. Of the 866 metric tons (955 tons) of barite used, 87 percent was discharged, six percent was left downhole, and seven percent was unaccounted for. For bentonite plus drilled solids, 89 percent was discharged, one percent was left downhole and ten percent was unaccounted for. For the combined usage of lignite, and chrome lignosulfonate, and

TABLE V-3 [144]

PROPOSED DRILLING FLUID DISCHARGE RATES FOR A GULF OF MEXICO WELL DRILLING PROGRAM
(Shell Oil Company, 1978)

				Drilling Fluid			Drilled Cuttings	
Depth Interval (feet)	Drilling Time (days)	Bit Diameter (inches)	Mud Type[a]	Average Daily Discharge (bbl)	Total Volume Discharged (bbl) Continuous	Bulk	Average Daily Discharge (bbl)	Total Volume of Cuttings Discharged (bbl)
0-500	1	29	SW	2,500	2,500		722	722
500-1,000	2	26	SW	2,500	5,000	1,000	289	578
1,000-3,000	6	22	SW-gel	200	1,200		265	1,588
3,000-8,000	27	15	LT FCLS-FW/SW	50	1,350		65	1,757
8,000-16,000	61	12-1/4	FCLS-FW	50	3,050		28	1,733
16,000-20,000	38	8-3/4	FCLS-FW	50	1,900	800	10	361
Total	135				15,000	1,800		6,739

Overall Daily Average: drilling fluid = 116 bbl/day
cutting = 47 bblday

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[a] SW (Saltwater plus natural mud)
SW-gel (saltwater plus bentonite or attapulgite)
LT FCLS-FW/SW (a lightly-treated ferrochrome lignosulfonate freshwater/saltwater system)
FCLS-FW (a freshwater ferrochrome lignosulfonate system)

TABLE V-4 [244]

SUMMARY OF DRILLING FLUID AND CUTTINGS DISCHARGE RATES BY GEOGRAPHICAL LOCATION (bbl/day/well)

OCS Location	Drilling Fluids	Drill Cuttings	Combined Average Daily Discharge
Gulf of Mexico	116	47	163
Mid-Atlantic	155	33	188
Mid-Atlantic	190-219	35	225-254
Lower Cook Inlet, Alaska	93-203	27-47	120-150
Tanner Bank, California	33-50	7-22	40-72

TABLE V-5 [144]

BASIC DRILLING FLUID ADDITIVES USAGE VERSUS DEPTH OF WELL

(DEPTH > 9,000 FEET)

Depth (Thousands of Feet)	Materials Used (Tons)							
	Total Additives	Barite	Clays	Lignosulfonates	Lignites	Cellulosic Polymers	Caustic (NaOH)	Soda Ash Bicarbonate
9.8	709	603	42	14	14	0	39.3	0.3
10.4	697	511	117	12.6	3.4	2.6	35.1	1.5
10.6	750	608	31	29	23.7	2.4	25.1	0.5
11.0	300	239	38	6.3	2.5	1.5	6.4	1.3
11.1	852	732	47	24	13.6	1.1	14.7	0
13.4	1329	1079	49	21	2.5	5.4	16.8	2.3
13.5	1198	977	84	40	16.1	1.7	28.3	0.6
16.3	1573	953	454	48	51.7	4.7	55.2	0
18.6	1975	1660	58	46	2.5	14.6	41.5	2.8
19.5	2118	1798	59	50	2.5	15.6	45.0	2.8
21.1	1724	1078	387	41	40.7	9.4	140	31.4

cellulose polymer, 95 percent of the material was discharged, and five percent was unaccounted for. The amounts that are unaccounted for are presumed to be lost to the formations and left downhole.

Composition

A data gathering program was initiated by the Agency for this rulemaking to evaluate the characteristics of water-based drilling fluids. One objective of this on-going program is to examine test procedures proposed as analytical methods applicable to this industrial subcategory for measuring acute toxicity and for detecting the presence of diesel oil in mud discharges. A second objective is to evaluate test results derived from these and other Agency-approved analytical procedures in the development of effluent limitations guidelines and standards.

The first phase of this program involved the selection and specification of test muds. The Agency's intent was to select a group of the more commonly used water-based mud formulations for testing purposes. In doing so, the Agency relied upon information gathered during the development of NPDES permits issued in 1978 to operators drilling on leases in the Atlantic Ocean. Eight basic mud types were defined during the Mid-Atlantic Bioassay Program conducted by the Atlantic Ocean permittees in cooperation with EPA Region II and the Offshore Operators Committee (OOC). These eight generic mud types were selected to encompass virtually all water-based muds, exclusive of specialty additives, used on the Outer Continental Shelf. The components of each mud type were identified, and allowable concentration ranges for each component were specified, as presented in Table V-6. Bioassay tests were conducted as a permit condition, and results of the Mid-Atlantic Program indicated that all eight generic muds demonstrated relatively low toxicity. Under their

TABLE V-6

EPA GENERIC DRILLING FLUIDS LIST [245]

Type of Fluid	Base Components	Typical Concentration Range (lb/bbl)
1. Potassium/ Polymer mud	Caustic Soda	0.5 - 3
	Barite	0.0 - 450
	Cellulose Polymer	0.25 - 5
	Drilled Solids	20.0 - 100
	Potassium Chloride	5.0 - 50
	Seawater or Fresh Water	As needed
	Starch	2.0 - 12
	Xanthan gum	0.25 - 2
2. Seawater/ Lignosulfonate Mud	Attapulgite or Bentonite	10.0 - 50
	Barite	25.0 - 450
	Caustic Soda	1.0 - 5
	Cellulose Polymer	0.25 - 5
	Drilled Solids	20.0 - 100
	Lignite	1.0 - 10
	Lignosulfonate	2.0 - 15
	Seawater	As needed
	Soda Ash/Sodium Bicarbonate	0.0 - 2
3. Lime Mud	Barite	25.0 - 180
	Bentonite	10.0 - 50
	Caustic Soda	1.0 - 5
	Drilled Solids	20.0 - 100
	Freshwater or Seawater	As needed
	Lignite	0.0 - 10
	Lignosulfonate	2.0 - 15
	Lime	2.0 - 20
	Soda Ash/Sodium Bicarbonate	0.0 - 2
4. Nondispersed Mud	Acrylic Polymer	0.5 - 2
	Barite	25.0 - 180
	Bentonite	5.0 - 15
	Drilled Solids	20.0 - 70
	Freshwater or Seawater	As needed
5. Spud Mud (slugged intermittently with seawater)	Attapulgite or Bentonite	10.0 - 50
	Barite	0.0 - 50
	Caustic Soda	0.0 - 2
	Lime	0.5 - 1
	Seawater	As needed
	Soda Ash/Sodium Bicarbonate	0.0 - 2

TABLE V-6 (CONTD)

EPA GENERIC DRILLING FLUIDS LIST [245]

Type of Fluid	Base Components	Typical Concentration Range (lb/bbl)
6. Seawater/Fresh-Water Gel Mud	Attapulgite or Bentonite	10.0 - 50
	Barite	0.0 - 50
	Caustic Soda	0.5 - 3
	Cellulose Polymer	0.0 - 2
	Drilled Solids	20.0 - 100
	Lime	0.0 - 2
	Seawater or Fresh Water	As needed
	Soda Ash/Sodium Bicarbonate	0.0 - 2
7. Lightly Treated Lignosulfonate Fresh Water/ Seawater Mud	Barite	0.0 - 180
	Bentonite	10.0 - 50
	Caustic Soda	1.0 - 3
	Cellulose Polymer	0.0 - 2
	Drilled Solids	20.0 - 100
	Lignite	0.0 - 4
	Lignosulfonate	2.0 - 6
	Lime	0.0 - 2
	Seawater to Fresh Water Ratio	1:1 approx.
	Soda Ash/Sodium Bicarbonate	0.0 - 2
8. Lignosulfonate Fresh Water Mud	Barite	0.0 - 450
	Bentonite	10.0 - 50
	Caustic	2.0 - 5
	Cellulose Polymer	0.0 - 2
	Drilled Solids	20.0 - 100
	Fresh Water	As needed
	Lignite	2.0 - 10
	Lignosulfonate	4.0 - 15
	Lime	0.0 - 2
	Soda Ash/Sodium Bicarbonate	0.0 - 2

NPDES Permit, operators were allowed to discharge muds that complied with these specifications.

This generic mud concept has been employed by other EPA regional offices involved in drilling fluid discharge permitting. The concept is based on stipulation of general mud types, classified by major components, which are considered acceptable for discharge. Any other additives to be used in a mud system and then discharged would require prior review and authorization for discharge by the permitting region. As an example, Table V-7 lists mud components and specialty additives that have been authorized for discharge by EPA Region X and have been incorporated in general NPDES permits to be issued for that region.

Since the previously identified eight generic mud types have been considered operationally satisfactory for the majority of offshore drilling situations, the Agency selected the same mud compositions for investigation under the BAT and NSPS regulation development program. However, it was determined that, for regulation development, tests would be more appropriately conducted on mud mixtures with components at the upper limits of allowable concentrations. Laboratory-prepared muds, based on the eight generic fluid formulations with most components present at the upper limits of allowable concentration, were obtained from the Petroleum Equipment Suppliers Association (PESA) in mid-1983. Samples of these formulations were sent to EPA Laboratories for chemical, physical, and biological testing. Bioassay data collected over the past five years by both government and industry sponsored studies on the acute toxicity of drilling fluids were considered unsatisfactory as a basis for establishing effluent limitations because of non-standard testing procedures and a high degree of variability among testing laboratories. The Agency therefore developed a proposed standard method for measuring acute toxicity of drilling fluids for this industrial

TABLE V-7

MUD COMPONENTS AND SPECIALTY ADDITIVES AUTHORIZED FOR DISCHARGE BY EPA REGION X

Additive Function	Description	Maximum Allowable Concentration (lb/bbl, unless otherwise noted)
Substitute for Attapulgite Clay in Generic Muds 2, 5 and 6	o Sepiolite	50
Detection of Filtrate Re-Entry into Mud System	o Ammonium nitrite	200 mg/l nitrate
	o Sodium nitrate	200 mg/l nitrate
Detection of Formation Water Intrusion	o Sodium chloride	50,000 mg/l chloride
Mud Lag Time Measurement	o Calcium carbide	As needed
H_2S Scavenging	o Zinc carbonate and lime	As needed
	o Basic zinc carbonate	As needed
	o Zinc oxide	As needed
Viscosifier	o Xanthan gum polymer	2
Lost Circulation Materials	o Flakes of silicate mineral mica	45
	o Crushed granular nut hulls	As needed
	o Vegetable plus polymer fibers, flakes, and granules	50
Friction Reducers	o Plastic spheres	8
	o Liquid triglycerides in a vegetable oil	6
	o Oleates in mixed alcohols	2
	o Phosphoric acid esters and triethanolamine	0.4
Defoamer	o Aluminum stearate	0.2
Dispersant	o Sodium polyphosphate	0.5

subcategory (see Appendix C of this document). Toxicity tests were then conducted at EPA's Environmental Research Laboratories in Gulf Breeze, Florida and Narragansett, Rhode Island using the standard bioassay procedure as described in Appendix C of this document. Analyses for oil content, biochemical oxygen demand, chemical oxygen demand, total organic carbon, and priority pollutants (excluding pesticides) were also performed at EPA contract laboratories, along with the static sheen test described in Appendix A of this document.

To examine the characteristics of oil contaminated muds, the Agency also obtained, through PESA and OOC, samples of two of the generic mud formulations spiked with various amounts of mineral and diesel oils. The two mud types selected were those that are most often used in drilling situations that require oil additives. The same analytical procedures were used to test both the spiked and unspiked formulations.

One drilling fluid constituent that is a focus of concern is diesel oil, which may be used as the primary component in conventional oil-based drilling fluids, and is a fuel oil readily available offshore for use as a spotting fluid and lubricating agent in water-based muds. Research sponsored by both industry and government agencies has shown that diesel oil contributes significantly to the acute toxicity of such drilling fluids. To add to the information already available in the literature on the chemical makeup of diesel oil, the Agency gathered and tested samples of commercially available diesel fuels and a diesel mud additive from an offshore drilling operation in the Gulf of Mexico. Samples were analyzed for the organic priority pollutant compounds using gas chromatography/mass spectrometry. Gas chromatography methods are also being used to determine the presence of diesel oil in drilling fluids.

The Offshore Operators Committee is also conducting a program to collect data on the organic constituents of diesel and mineral oils used as drilling fluid additives [271]. The Agency is participating in this program which will examine the differences in chemical composition between diesel and mineral oil, and evaluate methods for measuring the diesel content of drilling fluids.

Another major constituent of drilling fluid systems is barium sulfate, commonly called barite, a mineral used primarily as a weighting agent to control downhole pressures. Commercial forms of barite can contain various impurities, including trace metals. To investigate the presence of these contaminants, the Agency obtained samples of barite from four different sources and analyzed them for priority pollutant metals. The Agency intends to continue its survey of the quality and availability of commercial barite stocks with the assistance of PESA.

EPA will continue to evaluate the gas chromatography method for detecting the presence of diesel oil, the proposed Drilling Fluids Toxicity Test, and the Static Sheen Test. Interlaboratory validation programs will be carried out before the promulgation of final regulations to determine the precision and accuracy of these methods.

Results. As discussed above, the Agency selected eight generic, water-based mud types for investigation. Chemical, physical, and biological analyses were conducted on laboratory-prepared samples of these eight formulations, both with and without oil additives. Samples were hot-rolled prior to testing to simulate the downhole pressures and temperatures to which spent muds would be subjected.

Results of chemical and physical analyses [249] to identify selected characteristics of the eight generic muds are summarized in Table V-8. Biochemical oxygen demand (5 day) and ultimate oxygen demand (20 day) tests were performed with activated seed (ACT) and polyseed (POLY) in artificial seawater (SOW). Oil and grease analyses were conducted by sonification and extraction and by soxhlet extraction methods.

Static sheen tests [249] were conducted on the generic muds using the proposed methodology presented in Appendix A. Free oil was not detected in any of the eight base formulations that did not contain oil additives. Sheen tests were also conducted on water-based muds that contain various amounts of mineral and diesel oil. The two generic mud types selected for testing were those that are most often used in drilling situations that require oil additives. Both mineral and diesel additions were found to cause sheens on test waters. However, water-based muds with diesel spikes produced sheens at spiking concentrations as low as one percent by volume.

Analytical results for organics and metals [249] are summarized in Tables V-9 and V-10. None of the organic priority pollutants were detected in any of the water-based generic drilling fluid formulations using gas chromatography/mass spectrometry methods. Atomic absorption spectrometry was used for metals analyses with a combination of flame, graphite furnace, and cold vapor techniques. A total of 10 of the 13 metals on the priority pollutant list were found in detectable quantities in the generic formulations. Cadmium and mercury, in particular, were present in all muds tested, but at levels below 1 mg/kg each.

Bioassay results [248] indicate that the acute toxicity of the generic muds range considerably. No median effects (50 percent mortality) were observed for three of the eight mud types, whereas the most toxic was found to be the potassium polymer mud. Its suspended particulate phase showed a 96-hr LC-50 of 3 percent

TABLE V-8

CONVENTIONAL PARAMETERS FOR GENERIC DRILLING FLUIDS [249]

Generic Mud No.	Type of Mud	pH	Density	% Weight Loss (103°C) mg/kg(a)	BOD-5 ACT in SOW mg/kg(b)	BOD-5 POLY in SOW mg/kg(b)	UOD-20 ACT in SOW mg/kg(b)	UOD-20 POLY in Sow mg/kg(b)	TOC mg/kg(c)	COD mg/kg(b)	Oil and Grease Ext. and Sonification mg/kg(b)	Oil and Grease Soxhlet Extraction mg/kg(a)
1	KCL Polymer Mud	8.05	1.74	34.1	1813	2037	4223	3407	3,040	8,000	532	4,860
2	Seawater Lignosulfonate Mud	10.10	2.15	26.6	1483	1373	2717	2330	15,000	39,900	1,270	2,750
3	Lime Mud	11.92	1.73	44.0	1657	2743	3207	3963	15,000	41,200	796	1,240
4	Non-dispersed Mud	8.60	1.44	659.6	< 50	10	136	286	1,220	4,200	520	1,820
5	Spud Mud	8.10	1.09	90.1	< 50	9	160	124	100	420	597	140
6	Seawater/Freshwater Gel Mud	7.95	1.09	88.0	181	216	130	285	686	1,800	661	672
7	Lightly Treated Lignosulfonate Mud	8.50	1.44	56.2	1470	1386	2187	1733	5,650	15,200	1,710	572
8	Lignosulfonate Freshwater Mud	8.60	2.12	27.1	1530	1393	2413	1980	14,200	34,900	1,400	7,380
2-01	Mud 2 + 1% Vol. Mineral Oil	10.95	2.15	26.4	1416	2223	4073	5803	15,900	46,100	2,730	2,400
2-05	Mud 2 + 5% Vol. Mineral Oil	9.75	2.07	27.2	3416	2157	8340	7473	26,300	98,300	11,700	23,400
2-10	Mud 2 + 10% Vol. Mineral Oil	8.55	2.04	25.7	1558	1877	9273	6190	36,500	144,000	14,800	40,400
8-01	Mud 8 + 1% Vol. Mineral Oil	8.00	2.21	27.0	1373	2383	4423	4297	13,400	53,800	1,990	2,560
8-05	Mud 8 + 5% Vol. Mineral Oil	9.22	2.23	26.3	2207	2023	9773	6940	20,800	75,300	7,080	7,670
8-10	Mud 8 + 10% Vol. Mineral Oil	8.50	2.25	25.6	1423	1633	7863	6497	24,200	99,600	12,300	2,800

All data wet weight
(a) Average of duplicates
(b) Average of triplicate
(c) Average of three triplicates

TABLE V-9

ORGANIC POLLUTANTS DETECTED IN GENERIC DRILLING FLUIDS [249]

Conc. in ug/kg (all base neutral fraction)

Generic Mud No.	Type of Mud	Phenanthrene	Dibenzofuran	N-Dodecane C-12	Diphenylamine	Biphenyl
1	KCL Polymer Mud			899		
2	Seawater Lignosulfonate Mud					
3	Lime Mud			809		
4	Non-dispersed Mud			819		
5	Spud Mud			854 (822)		
6	Seawater/Freshwater Gel Mud			847 (802)		
7	Lightly treated Lignosulfonate Mud			736		
8	Lignosulfonate Freshwater Mud			780		
2-01	Mud 2 + 1% Vol. Mineral Oil	1060		726		
2-05	Mud 2 + 5% Vol. Mineral Oil	8270	827	6540		867
2-10	Mud 2 + 10% Vol. Mineral Oil	19300	1040	13300	4280	2290
8-01	Mud 8 + 1% Vol. Mineral Oil					
8-05	Mud 8 + 5% Vol. Mineral Oil	5580		9380		
8-10	Mud 8 + 10% Vol.	11100	933	8720	5200	1120

TABLE V-10

METAL CONCENTRATIONS IN GENERIC DRILLING FLUIDS [249]

Generic Mud No.	Type of Mud	Zn mg/kg Flame (a)	Be mg/kg Flame(a)	Al mg/kg Flame(a)	Ba mg/kg Flame(a)	Fe mg/kg Flame(a)	Cd mg/kg Flame(a)	Cr mg/kg Flame(a)	Cu mg/kg Flame(a)	Ni mg/kg Flame(a)	Pb mg/kg Flame(a)	Hg mg/kg Flame(a)	Ag mg/kg Furnace(a)	As mg/kg Furnace(a)	Se mg/kg Furnace(a)	Sb mg/kg Furnace(a)	Tl mg/kg Furnace(a)
1	KCL Polymer Mud	26.2	< 1.0	190	246	1,890	0.22	< 3.0	3.96	< 6.0	7.74	0.261	0.089	4.64	< 3.0	4.00	0.078
2	Seawater Lignosulfonate Mud	42.4	< 1.0	1150	74.0	2,860	0.472(b)	764	27.5	< 6.0	1.82(b)	0.264	0.126	2.40	< 3.0	0.260	0.201
3	Lime Mud	37.0	< 1.0	743	41.2	2,170	0.378(b)	908	40.6	< 6.0	1.42(b)	0.753	0.314	17.2	< 3.0	1.06	0.129
4	Non-dispersed Mud	35.9	< 1.0	876	286	1,120	0.446(b)	< 3.0	6.78	< 6.0	41.2	0.437	0.228	5.25	< 3.0	0.473	0.114
5	Spud Mud	8.68	< 1.0	347	293	833	0.74(b)	< 3.0	1.61	< 6.0	52.5	< 0.010	< 0.060	0.258	< 3.0	< 0.060	< 0.060
6	Seawater/Freshwater Gel Mud	3.28	< 1.0	536	65.4	392	0.42(b)	< 3.0	0.70	< 6.0		0.297	< 0.060	0.621	< 3.0	< 0.60	< 0.060
7	Lightly Treated Lignosulfonate Mud	2.26	< 1.0	395	408	660	0.142(b)	299	2.86	< 6.0	1.53(b)	0.0961	< 0.060	0.497	< 3.0	< 0.060	< 0.060
8	Lignosulfonate Freshwater Mud	90.4	< 1.0	1150	54.6	5,110	0.36	770	72.2	< 6.0	17.8	0.355	0.244	11.7	< 3.0	0.794	0.071
2-01	Mud 2 + 1% Vol. Mineral Oil	43.4	< 1.0	1200	71.3	2,520	0.395(b)	740	26.8	7.76	6.83	0.107	0.110	1.47	< 3.0	0.239	0.175
2-05	Mud 2 + 5% Vol. Mineral Oil	40.8	< 1.0	1400	144.1	3,350	0.717(b)	720	26.0	9.80	6.20	0.091	0.124	1.70	< 3.0	0.522	0.184
2-10	Mud 2 + 10% Vol. Mineral Oil	46.0	< 1.0	955	47.5	2,800	0.470(b)	640	26.1	6.98	1.17(b)	0.072	0.110	1.97	< 3.0	0.160	0.166
8-01	Mud 8 + 1% Vol. Mineral Oil	86.8	< 1.0	988	1240	4,980	0.18	610	68.9	< 6.0	24.5	0.391	1.39	12.2	< 3.0	2.65	0.080(c)
8-05	Mud 8 + 5% Vol. Mineral Oil	66.6	< 1.0	862	27.0	3,940	0.28	541	77.3	< 6.0	13.0	0.368	1.11	9.61	< 3.0	2.70	0.074
8-10	Mud 8 + 10% Vol.	77.8	< 1.0	857	39.5	5,020	0.36	560	42.8	< 6.0	9.48	0.287	1.14	9.24	< 3.0	2.02	0.062(c)

(a) Dry weight basis, average of two samples
(b) Samples run by graphite furnace.
(c) Single analysis

by volume, as measured by the proposed bioassay test method as described in Appendix C of this document. A summary of bioassay results is presented in Table V-11.

Drilling fluid toxicity was found to increase with the addition of mineral oil, but to a lesser extent than with diesel oil additions. These findings are consistent with results of other research activities conducted at EPA's Environmental Research Laboratory in Gulf Breeze, Florida. [240] The Agency will continue to investigate the toxicity of various mineral oil additives to determine which formulations are operationally adequate substitutes for the more toxic diesel oil and result in the least overall toxicity in generic drilling fluid formulations.

The Gulf of Mexico Offshore Operators Committee is conducting a series of studies to determine the differences in organic compounds in mineral and diesel oils and whether or not an analytical method can be used to definitively identify an oil as diesel. In this first phase report [271], three mineral oils and six diesels were examined using both the EPA GC method and a series of GC/MS methods measuring such parameters as individual aromatic compounds, alkylated phenols, organic sulfur compounds and several others. The compounds mentioned all showed promise as distinguishing parameters for determining the difference between mineral and diesel oil. In this phase the whole oils were examined. The next phase will examine oils after mixture in muds and subsequent extraction. Also in this phase, it will be necessary to determine the effect of several variables on the ability of the chosen parameters to distinguish between diesel and mineral oil.

Data obtained from the first phase of the OOC study are summarized in Table V-12.

TABLE V-11

RESULTS OF ACUTE TOXICITY TESTS WITH GENERIC DRILLING FLUIDS AND MYSIDS (*MYSIDOPSIS BAHIA*) [240]

Test Location	Generic Mud No.	Definitive Test (a) (96-h LC_{50} & 95% CL)	Positive Control (a) (96-h LC_{50} & 95% CL)	Definitive Test (b) (96-h LC_{50} & 95% CL)
EPA/ORD, Gulf Breeze	1	2.7% SPP (c) (2.5-2.9)	5.8 ppm (d) (4.3-7.6)	3.3% SPP (3.0-3.5)
	2	51.6% SPP (47.2-56.5)	7.5 ppm (6.9-8.1)	62.1% SPP (58.3-65.4)
	3	16.3% SPP (12.4-20.2)	7.3 ppm (6.6-8.1)	20.3% SPP (15.8-24.3)
	4	12% mortality in 100% SPP	3.4 ppm (2.8-4.1)	--
	5	12% mortality in 100% SPP	Same as for #1	--
	6	20% mortality in 100% SPP	6.0 ppm (5.4-6.6)	--
	7	65.4% SPP (54.4-80.4)	Same as for #6.	68.2% SPP (55.0-87.4)
	8	29.3% SPP (27.2-31.5)	Same as for #3	30.0% SPP (27.7-32.3)
EPA/ORD, Narragansett	1	2.8% (2.5-3.0)	6.2 ppm (4.4-11)	--
	5	No mortality in 100% SPP	3.3 ppm (2.6-3.8)	--

LC_{50} - Lethal concentration to 50% of test organisms   CL - confidence limit
SPP - Suspended particulate phase

(a) Calculations by moving average; no correction for control mortality unless stated.

(b) Calculations by SAS probit; correction for all control mortality. Analyses performed R. Clifton Bailey, U.S. EPA, Program Integration and Evaluation Staff (WH-586), Office of Water Regulations and Standards, Washington, D.C. 20460

(c) The suspended particulate phase (SPP) was prepared by mixing 1 part drilling fluid with 9 parts seawater. Therefore, these values should be multiplied by 0.1 in order to relate the 1:9 dilution tested to the SPP of the whole drilling fluid.

(d) Corrected for 13% control mortality.

TABLE V-12
ORGANIC CONSTITUENTS OF DIESEL AND MINERAL OILS [271]

Conc. in mg/ml, unless noted otherwise

Organic Constituents	Gulf of Mexico Diesel	Calif. Diesel	Alaska Diesel	EPA/API Ref. Fuel Oil	Mineral Oil A	Mineral Oil B	Mineral Oil C
Benzene	ND	0.02	0.02	0.08	ND	ND	ND
Ethylbenzene	ND	0.47	0.26	2.01	ND	ND	ND
Naphthalene	1.43	0.66	0.48	0.86	0.05	ND	ND
Fluorene	0.78	0.18	0.68	0.45	ND	0.15	0.01
Phenanthrene	1.85	0.36	1.61	1.06	ND	0.20	0.04
Phenol (ug/g)	6.0	ND	1.2	ND	ND	ND	ND
Alkylated benzenes (a)	8.05	10.6	1.08	34.3	30.0	ND	ND
Alkylated naphthalenes (b)	75.7	18.0	25.2	38.7	0.28	0.69	ND
Alkylated fluorenes (b)	9.11	1.60	5.42	7.26	ND	1.74	ND
Alkylated phenanthrenes (b)	11.5	1.41	4.27	10.2	ND	0.14	ND
Alkylated phenols (ug/g) (c)	52.9	106.3	6.60	12.8	ND	ND	ND
Total biphenyls (b)	15.0	4.03	6.51	13.5	0.23	5.57	0.02
Total dibenzothiophenes (ug/g)	760	1200	900	2100	ND	370	ND
Aromatic content (%)	23.8	15.9	11.7	35.6	10.7	2.1	3.2

Note: The study characterized six diesel oils and three mineral oils. For the purpose of the general comparison and summary presented above, the Alaska, California, and Gulf of Mexico diesels are assumed to be representative of those used in offshore drilling operations.

ND = Not Detectable

(a) Includes C_1 through C_6 alkyl homologues
(b) Includes C_1 through C_5 alkyl homologues
(c) Includes cresol and C_2 through C_4 alkyl homologues

GC/MS analyses of diesel additives show the presence of organic priority pollutants, including benzene, ethylbenzene, naphthalene, fluorene, phenanthrene, and phenol. Limited analyses of mineral oils also show the presence of organics, including benzene, naphthalene, phenanthrene, and fluorene.

Drill Cuttings

Drill cuttings are the solid particles removed by the drill and carried to the surface by the drilling fluid. Solids control equipment operates continuously when the drilling rig is in operation. Actual drilling accounts for about one-third to one-half of the time a drilling rig is on-site. Continuous and frequent, intermittent discharges are normally generated by the operation of solids control equipment. Such discharges occur for periods of less than one hour to 24 hours per day, depending on type of operations and well conditions. Typical sources and discharge rates are presented in Table V-13.

Volume. In general, the bulk of the discharged material (about 2,000 bbl) is generated within the first 5,000 ft of drilling; another 2,000 bbl are produced between 5,000 ft and 15,000 ft; by the 20,000 ft level, discharges have increased by only another 1,000 bbl to a total of 5,000 bbl [144]. This is because the diameter of the bore hole decreases with depth resulting in lower volumes of drill cuttings requiring removal. Approximate quantities of drilled solids for typical exploratory and developmental wells are presented in Tables V-3, V-4 and V-14. The average daily discharge also decreases with depth because drilling slows down as depth increases.

Composition. Drill cuttings themselves are generally inert particles. However, cuttings associated with hydrocarbon base drilling fluids or from petroleum bearing formations adsorb a

TABLE V-13 [244]

SOURCES, DISCHARGE RATES, AND DISCHARGE FREQUENCY OF CONTINUOUS DISCHARGES FROM A SINGLE WELL LOCATED IN LOWER COOK INLET, ALASKA

(Atlantic Richfield Company, 1978)

Source	Rate (bbl/hr)	Frequency
Shale shaker	1-2	Continuous during drilling
Desander	3	2-3 hr/day during drilling
Desilter	16-17	2-3 hr/day during drilling
Centrifuge	30	1-3 hr; every 2-3 days
Sand trap	550-2650	2-10 min. every 2-3 days
Sample trap	1.5-3	5-10 min. every 2-3 days

TABLE V-14

DRILL CUTTINGS FROM TYPICAL EXPLORATION AND DEVELOPMENT WELLS[a] [179]

Drilling Interval		Well Diameter		Drill Cuttings			
				Exploratory		Development	
				Volume	Weight	Volume	Weight
(m)	(ft)	(cm)	(in)	bbl (m^3)	tons (mtons)	bbl (m^3)	tons (mtons)
0-46	0-150	90	36	187 (30)	72 (66)	187 (30)	72 (66)
46-300	150-1,000	80	32	846 (135)	332 (302)	846 (135)	332 (302)
300-1,370	1,000-4,500	50	20	1,361 (217)	534 (486)	1,361 (217)	534 (486)
1,370-3,000	4,500-10,000	38	15	1,206 (192)	506 (460)	1,206 (192)	506 (460)
3,000-3,660	10,000-12,000	38	15	439 (70)	184 (167)	-	-
3,660-4,600	12,000-15,000	25	10	291 (46)	131 (119)	-	-
Total				4,330 (690)	1,759 (1,600)	3,413 (543)	1,444 (1,310)

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[a] Hypothetical well depths: Exploratory - 4,600m (15,000 ft)
Development - 3,000m (10,000 ft)

film of oil on the particle surfaces. This film is bound to the particle by the polar forces of oil molecules and resists removal by washing operations.

Well Treatment Fluids

Well completion at the production zone is a critical operation, since many factors which are formation specific can lead to productivity impairment. Completion fluids are specially formulated to prevent damage to the formation which could be caused by intrusion of the drilling fluid into the fine interstices and voids. Completion fluid formulations are usually selected only after core samples of the production zone have been obtained and analyzed. However, there are several classes of fluids which are commonly utilized. These classes are listed in Table V-15.

Well workover occurs after a well has shown an appreciable decline in productivity. Since well workover occurs at the production zone, many of the fluids used for well completion may also be utilized. In addition, specialty fluids used to stimulate production may also be used as site specific conditions dictate. The fluids used for workover operations are also listed in Table V-15.

Volume. The amounts of treatment fluids used are well specific, and discharges are intermittent. Volumes ranging from 800 to 1,600 bbl/day during oeprations have been reported.

Composition. Typical fluid constituents are listed in Table V-15. Composition will vary significantly depending on the condition downhole and fluid properties needed to perform certain functions. Recent sampling and analysis data are not available for these waste streams.

TABLE V-15

PROPERTIES OF WELL TREATMENT FLUIDS

FLUID TYPE	TYPICAL CONSTITUENTS	DOSAGE/VOLUME	REF.
Completion Fluids*			
1. Clear Fluids (Low Solids)	Bentonite Polyvinyl Acetate Acrylamide Xantham Gum Polyanionic Cellulose Polymer Sodium Polyacrylates Hydroxypropyl guar Sodium Polyacrylate Corn and Potato Starches Carboxymethyl cellulose Hydroxyethyl cellulose	Total <5%/wt All Additives Range from 1.0 lb/bbl to 10.0 lb/bbl	[23]
2. High Solids Fluids	Same as Normal Drilling Fluids	-	[53] [57]
3. Acidifiers	Hydrofluoric Acid (HF) Fluorosilicates Hydrochloric Acid (HCl)	HCl:HF (4:1) 15% HCl	[57]
Workover Fluids*			
1. Formation Acidizing Fluids	Hydrofluoric Acid Fluorosilicates Hydrochloric Acid	HCl:HF (4:1) 15% HCl	[57]
2. Fracturing Fluids	Liquid Carbon Dioxide and Nitrogen Cellulose, Guar Gum Natural Polymers Cellulose Enzymes Ammonium Persulfate Crude Oil, Kerosene	-	[53] [57]
3. Clear Brines	Salts		[277]

*Additional additives to control lubricity, fluid loss, rheology, viscosity, filtration, corrosion, and foaming may be added as per Table V-7.

Produced Water

Produced water is a combination of the formation waters which existed prior to development plus any other fluids and chemicals, such as drilling, treatment, enhanced recovery, and oil separation agents, which have become mixed during the petroleum production process. Chemicals which may be added during production, and which may be present in produced water discharges, include: biocides, coagulants, corrosion inhibitors, cleaners, detergents, dispersants, emulsion breakers, paraffin control agents, reverse emulsion breakers, and scale inhibitors. The use of these chemicals varies substantially from platform to platform.

Volume. Produced water is the highest volume waste source in the offshore oil and gas industry. The volume of wastewater generated by this industry is somewhat unique when compared to most other industries for which wastewater generation is directly related to the quantity or quality of raw materials processed. By contrast, produced water can constitute from 2 to 98 percent of the gross fluid production at a given platform. In general, produced water volume is small during the initial production phase and increases as the formation approaches hydrocarbon depletion. Historically, over the life of a producing formation, approximately equal volumes of water and hydrocarbons will be produced. However, there are also instances in which no formation water is ever encountered and others for which an extensive amount of formation water is encountered at the start of production. Therefore, the volume of produced water at a given platform can be viewed as a highly site-specific natural phenomenon.

Table V-16 illustrates the wide range of produced water flows in major offshore oil producing areas. Correlation of produced water with oil and gas product is not feasible on an industry-wide basis.

TABLE V-16

OFFSHORE PRODUCED WATER DISCHARGE RATES
(Oil and Gas Production Platforms)

LOCATION	Produced Water Discharge Rates m^3/d	TYPICAL PRODUCED WATER DISCHARGE RATE $\overline{X}$ m^3/d	Median m^3/d	Range m^3/d	REFERENCES
Gulf of Mexico		884	664	31-2,709	[194] (10 platforms)
		514	440	56-1,120	[196] (4 platforms)
		227	-	0-28,000	[253] (600 platforms 1982-1983)
		302	-	0-25,600	[253] (426 platforms 1981-1982)
		1,523	383	21-23,850	[174] (30 platforms)
California		1,280	1,206	38-3,800	[191]
		1,072	-	736-1,280	[196] (3 platforms)
	2,220	-	-	-	[175] (Central Treatment Facility for 42 Wells)
		-	-	-	
	196				[175] (1 platform)
	3,180				[175] (1 platform)
Cook Inlet		504	547	2,272 (max)	[197] (Granite Point)
		105	105	25-204	(Platform Bruce)*
		9,310	9,429	10,978 (max)	(Trading Bay)
		1,270	-		[175] (Kenai)
		1,750	-		(Dillon)

* Produced water and deck drainage commingled.

Composition. Prior to the initiation of this program, very little data existed on the composition of produced water other than the conventional parameters which have been studied in earlier programs. Therefore, the Agency embarked on a systematic effluent survey to identify and quantify the characteristics of produced water with regard to priority toxic pollutants. Specific characteristics of these wastes are highly dependent on geographical location. Therefore, separate discussions are provided on specific characteristics of wastes as obtained in sampling programs conducted in the three major offshore producing areas of the United States, i.e., the Gulf of Mexico, Alaska and California.

The first study consisted of a preliminary screening survey conducted at 6 platforms in the Gulf of Mexico to determine the presence or absence of priority pollutants in produced water discharges. The results of this study indicated that considerable quantities of organic priority pollutants (including: benzene, ethylbenzene, toluene, phenol and naphthalene) and metallic priority pollutants (such as chromium, lead, nickel and zinc) were almost universally present in produced water. In addition to the indication that priority pollutants were present, this study also provided information necessary for the development of the analytical protocols which would be utilized in the full-scale survey. In a separate effort during this time period, the Agency concluded the development of an improved analytical protocol for the analysis of organic priority pollutants. This improved method, however, had not been tested with highly saline effluents such as oil field brine for which the total dissolved solids is typically several times greater than that of seawater. For this purpose, a limited sampling program was conducted at two platforms with the resulting samples sent to 10 laboratories (both private and industry) to determine if any unforeseen problems could arise in the full-scale program. As a result of this study, some modifications to the original analytical methods were developed. A complete description of the analytical methods utilized and the modifications to these methods where required are contained in the data evaluation reports which are referenced in the following sections that summarize the information obtained in the Gulf of Mexico, Alaska and California verification sampling programs.

Gulf of Mexico Sampling Program - During the period of October 9 through October 30, 1981, 30 oil and gas production platforms located in the Gulf of Mexico were sampled to characterize the quantities of selected conventional, non-conventional and priority pollutants present in their produced brine discharges [174]. Table V-17 presents the production characteristics of the 30 sites selected. Overall, 79 individual samples were collected and analyzed for the parameters listed in Table V-18. Twenty of the 79 samples collected were obtained from the influent to the platform treatment system indicated on Table V-17, while the remaining 59 were treated effluent samples. Table V-19 presents an overall summary of occurrence of the organic priority pollutants detected in the effluents. As can be seen from this table, benzene, ethylbenzene, naphthalene, phenol, toluene, 2,4-dimethylphenol and bis-(2-ethylhexyl) phthalate were observed in over 50 percent of the effluent samples analyzed. The platform average values of these pollutants are summarized in Table V-20. An additional 15 organics were detected far less frequently. The occurrence for these parameters ranged from 2 to 32 percent of the effluent samples analyzed. Table V-21 presents the overall summary of occurrence for the metallic priority pollutants while Table V-22 contains concentrations of metals in the effluents. As can be noted from this table, zinc is the only metal regularly measured above the Lowest Reportable Value (a measure of the sensitivity of the method). The platform average values for the conventional and non-conventional parameters analyzed are presented in Table V-23.

TABLE V-17

CHARACTERISTICS OF PLATFORMS SELECTED FOR THE GULF OF MEXICO SAMPLING PROGRAM [174]

Number	Platform	Company	Oil/Condensate (bbl/d)	Gas (MMCF/d)	Brine (bbl/d)	Treatment (2)
1	EC 33A	Conoco	76.6	15.2	62	OS and DISS
2	EC 14CF	Mobil	807	13.1	2005	OS
3	V 119D	Conoco	890	3.4	2817	OS and DISP
4	V 255A	Shell	950	14	1298	DISP
5	SMI 23B	Gulf	228	13.8	495	OS and DISP
6	V 39D	Shell	395	38	634	OS and DISP
7	SMI 6A	Exxon	250	0.2	625	OS
8	EI 57A-E	Marathon	1200	150	500-2000	OS
9	SMI 115A	Shell	750	45	1200	OS and DISP
10	EI 120CF	Mobil	3500(1)	5(1)	2000(1)	OS and DISS
11	SMI 130B	Shell	21500	63	9733	OS and DISP
12	EI 208B	Conoco	1501	0.2	350	DISP
13	EI 18CF	Shell	2000	30	22000	OS and DISS
14	EI 238A	Gulf	40	6	2	DISP
15	EI 296B	Placid	1500	100	1470	OS and DISS
16	SS 107(S94)	Chevron	501	1.2	4610	DISP
17	SS 107(S93)	Chevron	2875	5.0	12500	DISP
18	SS 219A	Amoco	3000	7	800-1000	OS
19	ST 177	Gulf	2800	10	1072	DISP
20	BM 2C	Shell	10794	11.7	6590	OS and DISP
21	BDC CF5	Texaco	873	2.8	11028	OS and DISP
22	ST 135	Gulf	6000	18	8400	DISP
23	WD 90A	Amoco	2244	10.7	15000	OS and DISP
24	WD 45E	Conoco	745	2.3	1578	DISP
25	WD 70I	Conoco	5273	15.5	10721	DISP
26	GIB DB600	Texaco	554	0.1	3796	OS and DISP
27	WD 105C	Shell	2091	12.1	7532	DISP
28	SP 62A	Shell	1800	1.3	3100	OS and DISS
29	SP 24/27	Shell	24000	40	150000	OS and DISP
30	SP 65B	Shell	5000	8	3000	OS and DISP

(1) Value for Sampling Period

(2) OS = Oil Skimming; DISS = Dissolved Gas Flotation; DISP = Dispersed Gas Flotation

TABLE V-18

COMPOUNDS ANALYZED IN THE GULF OF MEXICO SAMPLING PROGRAM [174]

Fraction	Compound Name
Tradi-tionals	Chloride
	Iron
	Oil & Grease
	Total Diss. Solids
Volatiles	Acrolein
	Acrylonitrile
	Benzene
	Bis (Chloromethyl)Ether
	Bromoform
	Carbon Tetrachloride
	Chlorobenzene
	Chlorodibromomethane
	Chloroethane
	Chloroform
	Dichlorobromomethane
	Dichlorodifluoromethane
	Ethylbenzene
	Methyl Bromide
	Methyl Chloride
	Methylene Chloride
	Tetrachloroethylene
	Toluene
	Trichloroethylene
	Trichlorofluoromethane
	Vinyl Chloride
	1,1-Dichloroethane
	1,1-Dichloroethylene
	1,1,1-Trichloroethane
	1,1,2-Trichloroethane
	1,1,2,2-Tetrachloroethane
	1,2-Dichloroethane
	1,2-Dichloropropane
	1,2-Trans-Dichloroethylene
	1,3-Dichloropropylene
	2-Chloroethyl Vinyl Ether
Semi-Volatiles	Acenaphthene
	Acenaphthylene
	Anthracene
	Benzidine
	Benzo(A) Pyrene
	Bis(2-Chloroethoxy) Methane
	Bis(2-Chloroethyl) Ether
	Bis(2-Chloroisopropyl) Ether
	Bis(2-Ethylhexyl) Phthalate
	Butyl Benzyl Phthalate
	Chrysene
Semi-Volatiles	Di-N-Butyl Phthalate
	Di-N-Octyl Phthalate
	Dibenzo(A,H)Anthracene
	Diethyl Phthalate
	Fluoranthene
	Fluorene
	Hexachlorobenzene
	Hexachlorobutadiene
	Hexachlorocyclopentadiene
	Hexachloroethane
	Indeno (1,2,3-C,D) Pyrene
	Isophorone
	N-Nitrosodi-N-Propylamine
	N-Nitrosodimethylamine
	N-Nitrosodiphenylamine
	Naphthalene
	Nitrobenzene
	P-Chloro-M-Cresol
	Pentachlorophenol
	Phenanthrene
	Phenol
	Pyrene
	1,12-Benzoperylene
	1,2-Benzanthracene
	1,2-Dichlorobenzene
	1,2-Diphenylhydrazine
	1,2,4-Trichlorobenzene
	1,3-Dichlorobenzene
	1,4-Dichlorobenzene
	11,12-Benzofluoranthene
	2-Chloronaphthalene
	2-Chlorophenol
	2-Nitrophenol
	2,4-Dichlorophenol
	2,4-Dimethylphenol
	2,4-Dinitrophenol
	2,4-Dinitrotoluene
	2,4,6-Trichlorophenol
	2,6-Dinitrotoluene
	3,3-Dichlorobenzidine
	3,4-Benzofluoranthene
	4-Bromophenyl Phenyl Ether
	4-Chlorophenyl Phenyl Ether
	4-Nitrophenol
	4,6-Dinitro-O-Cresol
Metals	Cadmium
	Chromium
	Copper
	Lead
	Nickel
	Silver
	Zinc

TABLE V-19

PERCENT OCCURRENCE OF ORGANICS FOR TREATED EFFLUENT SAMPLES GULF OF MEXICO SAMPLING PROGRAM [174]

PARAMETER (1)	NUMBER OF(2) VALID DETERMINATIONS	NUMBER OF TIMES DETECTED	PERCENT OF TIMES DETECTED
Benzene	59	59	100
Ethylbenzene	59	59	100
Naphthalene	59	59	100
Phenol	58	58	100
Toluene	59	59	100
2,4-Dimethylphenol	56	52	93
Bis (2-Ethylhexyl) Phthalate	59	47	80
Di-N-Butyl Phthalate	59	19	32
Fluorene	59	13	22
Diethyl Phthalate	59	12	20
Anthracene	29	3	10
Acenaphthene	59	4	7
Benzo(A) Pyrene	59	3	5
P-Chloro-M-Cresol	59	1	2
Dibenzo (A,H) Anthracene	59	1	2
Chlorobenzene	59	1	2
Di-N-Octyl Phthalate	59	1	2
3,4-Benzofluoranthene	59	1	2
11,12-Benzofluoranthene	59	1	2
Pentachlorophenol	59	1	2
1,1-Dichloroethane	59	1	2
Bis (2-Chloroethyl) Ether	59	1	2

(1) - Pollutants not listed were never detected
(2) - Number of samples which yielded valid analytical results

TABLE V-20

ARITHMETIC MEAN EFFLUENT CONCENTRATION OF ORGANIC PRIORITY POLLUTANTS (1) GULF OF MEXICO SAMPLING PROGRAM [174]

PLATFORM	BENZENE (µg/l)	ETHYLBENZENE (µg/l)	NAPHTHALENE (µg/l)	PHENOL (µg/l)	TOLUENE (µg/l)	2,4-DIMETHYLPHENOL (µg/l)
1	8852	930	1179	4125	5576	2294
2	1650	80	216	7067	1010	379
3	737	34	104	585	368	47
4	2206	249	72	1028	2953	141
5	683	187	239	10462	3451	256
6	11033	2064	368	2206	12541	432
7	340	21	50	1930	163	49
8	12040	270	610	20812	5670	710
9	2038	59	34	65	1540	4
10	3590	6010	107	930	1550	37
11	2250	202	66	208	1565	N-D
12	1160	44	120	240	620	106
13	3365	125	204	762	3842	70
14	4100	187	139	950	2490	N-D
15	2120	124	73	560	1710	N-D
16	298	94	171	1396	936	105
17	540	87	36	1439	570	111
18	2430	260	34	332	2200	27
19	315	22	218	705	230	21
20	1112	97	125	1829	1114	98
21	1012	74	193	2328	715	209
22	1214	38	44	840	1022	72
23	1370	99	137	1138	990	88
24	140	19	26	588	104	35
25	1778	356	164	1106	2305	94
26	400	110	140	108	590	48
27	450	44	120	664	342	55
28	2854	112	52	204	1440	15
29	1200	86	127	270	920	18
30	400	95	328	355	495	30

N-D - Not Detected

(1) - For Pollutants Detected in 50 Percent or More of All Effluent Samples

TABLE V-21

PERCENT OCCURRENCE OF METALS FOR TREATED EFFLUENT SAMPLES GULF OF MEXICO SAMPLING PROGRAM [174]

PARAMETER	NUMBER OF(1) VALID DETERMINATIONS	NUMBER(2) OF TIMES DETECTED	PERCENT OF TIMES DETECTED
Zinc	53	43	81
Copper	53	10	19
Nickel	53	3	6
Lead	59	2	3
Cadmium	59	1	2
Chromium	59	0	0
Silver	53	0	0

(1) - Number of Samples Which Yielded Valid Analytical Results

(2) - Number of Times Reported Concentratration Exceeds LRV

TABLE V-22

ARITHMETIC MEAN EFFLUENT CONCENTRATIONS OF PRIORITY POLLUTANT METALS(1) GULF OF MEXICO SAMPLING PROGRAM [174]

Platform	Zinc (µg/l)	Copper (µg/l)	Nickel (µg/l)	Lead (µg/l)	Cadmium (µg/l)
1	37	N-D	N-D	N-D	N-D
2	47	N-D	N-D	N-D	N-D
3	27	N-D	N-D	N-D	N-D
4	52	54	N-D	N-D	N-D
5	213	N-D	N-D	N-D	N-D
6	53	N-D	N-D	N-D	N-D
7	65	N-D	N-D	N-D	N-D
8	155	N-D	N-D	N-D	N-D
9	435	N-D	N-D	N-D	N-D
10	230	N-D	N-D	223	N-D
11	N-D	23	N-D	N-D	N-D
12	396	N-D	N-D	N-D	N-D
13	88	23	N-D	N-D	N-D
14	427	N-D	N-D	N-D	N-D
15	N-D	N-D	N-D	N-D	N-D
16	94	24	N-D	N-D	N-D
17	63	41	N-D	N-D	N-D
18	214	92	N-D	N-D	N-D
19	N-D	N-D	N-D	5700	98
20	28	8	N-D	N-D	N-D
21	145	N-D	N-D	N-D	N-D
22	202	23	138	N-D	N-D
23	202	1455	N-D	N-D	N-D
24	40	10	N-D	N-D	N-D
25	N-D	N-D	N-D	N-D	N-D
26	NVD	NVD	NVD	N-D	N-D
27	48	N-D	72	N-D	N-D
28	445	N-D	216	N-D	N-D
29	NVD	NVD	NVD	N-D	N-D
30	NVD	NVD	NVD	N-D	N-D

Notes: (1) For metals detected at least once above lowest reportable value

N-D = Not Detected

NVD = No Valid Determinations

TABLE V-23

ARITHMATIC MEAN EFFLUENT CONCENTRATIONS OF CONVENTIONALS AND NON-CONVENTIONALS GULF OF MEXICO SAMPLING PROGRAM [174]

Platform	Oil & Grease (mg/l)	Total Dissolved Solids (mg/l)	Total Iron (mg/l)	Chloride (mg/l)
1	51	33258	5	13500
2	22	98090	9	56500
3	32	147520	22	78000
4	53	121220	26	66500
5	24	155600	40	79000
6	10	60190	9	33500
7	33	145540	18	79000
8	28	176620	27	84000
9	35	258940	78	121000
10	66	175240	34	91000
11	42	163110	34	88750
12	30	145440	34	72500
13	74	170280	34	91250
14	66	160560	76	93000
15	29	151960	26	78000
16	514	123500	26	68750
17	24	110520	16	62500
18	400	232320	84	130500
19	40	334360	100	172500
20	24	131198	10	70833
21	54	114433	11	61917
22	7	178030	35	94000
23	82	100700	19	53000
24	16	120188	16	63042
25	88	68275	10	35750
26	74	6876	0	3400
27	89	165350	31	86500
28	22	242565	42	124500
29	19	100620	17	55500
30	218	109000	17	56500

N-D = Not Detected
NVD = No Valid Determinations

Alaska Sampling Program - There are two major oil and gas producing fields in Alaska: one is offshore in Cook Inlet (Kenai Peninsula) and the other is on the North Slope of the Brooks Range, onshore in Prudhoe Bay. Two operating sites were sampled in Cook Inlet - one treated produced water on the platform and the other onshore [175]. The Prudhoe Bay facility reinjects all produced water, thus treatment, in the conventional sense, of produced water is not provided. The pertinent characteristics of these facilities are shown in Table V-24. The analytical results of the effluent samples obtained from this program are summarized in Table V-25.

California Sampling Program - Sampling of produced water was carried out in the Santa Barbara Channel oil-producing area. Platforms located within three miles of the shoreline are within State of California jurisdiction, while platforms beyond that are within federal jurisdiction. Producing offshore platforms located in state waters usually deliver gross fluid onshore, where oil is separated from water and produced water is treated by multistage unit processes and then is discharged into coastal waters or reinjected. There is no overboard discharge from platforms operating in state waters. Platforms located in federally controlled waters treat and discharge produced water overboard. The overboard discharge is sometimes augmented by reinjection. Three facilities were selected to represent oil production in the Santa Barbara Channel:

1. Summerland Field, offshore from Carpinteria, east of Santa Barbara in state coastal waters. Treatment and discharge into coastal waters.

2. Ellwood Field, offshore from Ellwood, west of Santa Barbara in state coastal waters. Reinjection.

TABLE V-24

CHARACTERISTICS OF FACILITIES SELECTED FOR ALASKA SAMPLING PROGRAM [175]

Characteristic	Offshore Platform Cook Inlet	Onshore Treatment Cook Inlet	Prudhoe Bay Oil Field
Brine BBL	18,350	6,600	13,000
Oil BBL	1,300	12,500	92,100
Gas MCF	410	-	136,500
Brine Treatment	Oil Skimming + Reinjection	Oil Skimming + Flotation + Reinjection	Reinjection
% of Brine:			
Reinjected	59	33	100
Discharged	41	67	0
Sampling Date	10/12/81	10/13/81	10/20/81

TABLE V-25

ARITHMETIC MEAN EFFLUENT CONCENTRATIONS OBTAINED FROM THE ALASKA SAMPLING PROGRAM [175]

Parameter	Units	Offshore Platform Cook Inlet	Onshore Treatment Cook Inlet	Prudhoe Bay Oil Field
Organic Priority Pollutants				
Benzene	µg/l	7375	7240	1370
Ethylbenzene	µg/l	345	170	900
Toluene	µg/l	3025	2805	9630
Phenol	µg/l	1810	1683	3490
2,4-Dimethylphenol	µg/l	438	420	830
Naphthalene	µg/l	359	330	595
Bis-(2-ethylhexyl) Phthalate	µg/l	176	80	228
Priority Pollutant Metals				
Copper	µg/l	55	55	-
Mercury	µg/l	3	3	3
Zinc	µg/l	1750	21	N-D
Conventionals/Non-conventionals				
Oil & Grease	mg/l	17	15	10
Total Dissolved Solids	mg/l	24570	25880	19800
Chloride	mg/l	12200	13000	10220

3. Offshore platform in federal waters. Overboard discharge and reinjection.

Characteristics of these three facilities are presented in Table V-26. Analytical results for effluent samples collected in this program are summarized in Table V-27.

Produced Sand

Produced Sand is fine sand and clay particles which are separated from the crude oil and produced water.

Volume. Produced sand discharges may be continuous or intermittent depending on the volumes produced. Compared with typical maximum produced water discharge rates for the Gulf of Mexico of 4,000-40,000 m^3/d, typical maximum produced sand discharge rates are on the order of 4-40 m^3/d. One figure for produced sand, which is site-specific and cannot be considered typical, is 1 m^3 sand per 2,000 m^3 oil production. One general figure for southern California producing fields, which are considered to produce small quantities of produced sand, is 1 m^3/d. Another estimate is 2 kg/d per well.

Composition. Oil and grease is the primary pollutant parameter found with produced sand. Estimates of the oil and grease content after washing are less than 1 mg/l.

Deck Drainage

Deck drainage includes rainwater, wash water, and any lubrication or product spillage or leakage which may accumulate on the platform deck and enter the deck drainage system.

TABLE V-26

CHARACTERISTICS OF FACILITIES SELECTED FOR CALIFORNIA SAMPLING PROGRAM [175]

Characteristic	Ellwood Facility	Carpinteria Facility	Offshore Platform
Brine BBL	1,230	14,000	25,000
Oil BBL	9,200	6,400	17,000
Gas MCF	-	-	-
Brine Treatment	Filtration + Reinjection	Oil Skimming + Flotation	Flotation + Filtration + Reinjection
% Brine:			
Reinjected	100	0	20
Discharged	0	100	80
Sampling Date	6/23/82	6/2/82	6/10/82

TABLE V-27

AVERAGE EFFLUENT CONCENTRATION OBTAINED FROM THE CALIFORNIA SAMPLING PROGRAM [175]

Parameter	Units	Ellwood Facility	Carpinteria Facility	Offshore Platform
Organic Priority Pollutants				
Benzene	µg/l	4000	1463	286
Ethylbenzene	µg/l	348	148	140
Toluene	µg/l	2940	2750	544
Phenol	µg/l	1046	973	19
2,4-Dimethylphenol	µg/l	213	772	189
Naphthalene	µg/l	84	86	127
Bis-(2-ethylhexyl) Phthalate	µg/l	L 10	N-D	N-D
Priority Pollutant Metals				
Copper	µg/l	165	109	198
Lead	µg/l	113	N-D	77
Zinc	µg/l	220	46	78
Conventionals/Non-conventionals				
Oil & Grease	mg/l	N-A	5	N-A
Total Dissolved Solids	mg/l	N-A	22700	N-A
Chloride	mg/l	N-A	10500	N-A

L - Less than; N-D - Not Detected; N-A - Not Analyzed

Volume. Flows are intermittent, occurring during rainfall events and washdown operations. Typical deck drainage flow rates are shown in Table V-28.

Composition. Golumbek et al. compiled and analyzed self monitoring data on deck drainage supplied from 8 exploratory drilling platforms to characterize deck drainage before and after treatment. They reported average oil and grease concentrations between 10 and 85 mg/l [8]. Oil and grease and suspended solids are the primary pollutants of concern in the deck drainage. Total discharges are likely to be small. One estimate based on a survey of 23 U.S. platforms was less than 0.25 litres of oil and grease per day per platform [184].

Sanitary and Domestic Wastes

Sanitary and domestic wastes are generated by continuously manned production facilities and all drilling rigs during mobilization and operation. Continuously manned facilities generally discharge domestic wastes which originate from sinks, showers, laundry and food preparation areas.

Volume. At its highest occupancy, which generally occurs during well completion, drilling rigs support between 12 and 80 permanent occupants. Production platforms are categorized as unmanned, manned by 9 or fewer persons, or manned by 10 or more persons. Typical volumes of sanitary and domestic waste are 0.075 and 0.11 m^3/cap/day, respectively. The most extensive information on actual facility discharges are obtained from annual Discharge Monitoring Reports submitted to EPA. A review of DMR's submitted to Region VI from facilities in the Gulf of Mexico for the reporting periods 4/81 to 3/82 and 4/82 to 3/83 indicate that sanitary waste volumes range from 0.04 m^3/day to 2.65 m^3/day for facilities manned by 9 or fewer persons and 0.38

TABLE V-28

DECK DRAINAGE FLOW RATES

LOCATION	REFERENCE	SOURCE OF FLOW	m^3/d	NATURE OF FLOW
California	[188]	deck wash	0.1 (typical)	intermittent, not daily
Cook Inlet	[197]		0-1,500; 76 mean	-
Gulf of Mexico	[253]	total deck drainage	0-1,542 8 mean	950 sites intermittent

m^3/day to 22.7 m^3/day for facilities manned by 10 or more persons. During these same periods, domestic waste volume ranged from 0.08 m^3/day to 30.3 m^3/day.

Composition. Where physical treatment (incineration) of sanitary wastes is practiced, there is no pollutant discharge. Table V-29 contains typical discharge parameters for platforms providing separate wastewater treatment for sanitary waters. Table V-29 also shows typical domestic (gray) wastewater loadings and concentrations of biochemical oxygen demand (BOD) and suspended solids (SS).

Ballast Water

Ballast water and storage displacement water discharges are characterized by intermittent flow at high flow rates over a relatively short period (a few hours to a few days). Large storage volumes are required to allow offloading of large tankers. Volumes and discharge rates for tanker ballast water range from 49,000 to 115,000 m^3/d and average 55,000 m^3/d [197].

Miscellaneous Wastes

A description of the composition and handling of miscellaneous offshore production wastes is given in Table V-30.

TABLE V-29

TYPICAL OFFSHORE SANITARY AND DOMESTIC WASTE CHARACTERISTICS

	DISCHARGE RATE (m^3/cap/day)	LOADING		CONCENTRATION		
		BOD (kg/cap/day)	S.S (kg/cap/day)	BOD (mg/L)	S.S (mg/L)	RESIDUAL CHLOR (mg/L)
Sanitary waste (treated)	0.075	0.002 (1)	0.003 (1)	30	40	1.7
Domestic waste (direct discharge)	0.11	0.022 (2)	0.016 (2)	195	140	0

Sources:

(1) Adapted from [3]
(2) Adapted from [34]

TABLE V-30

PROPERTIES OF MISCELLANEOUS OFFSHORE PRODUCTION WASTES

WASTE TYPE	COMPOSITION	VOLUME	HANDLING	REF.
Desalination Brine				
reverse osmosis reject (potable water only)	TDS = 1.15 x seawater bisulphite added as biocide	20 m^3/d (several 100 gpd)	Continuous or intermittent direct discharge overboard	[188]
distillation (producing 65m^3 potable water and process water)	TDS = 2 x seawater TSS = 28 mg/l pH = 7.35 COD = 1,125 mg/l* Residual chlorine <0.1 mg/l Temperature increase <11°C	33 m^3/d	Mixed with cooling water	[190]
Cooling Water				
California production platform	Seawater Temperature increase <11°C	450 m^3/d (several thousand gph)	Direct discharge to the sea surface	[188]
California processing and storage platform	Seawater Temperature increase <11°C Residual chlorine 0.5 mg/l TSS = 28 mg/l pH = 7.35 COD = 1,125	10,500 m^3/d	Mixed with desalination waste and discharged to surface	[190]
Fire Control Test Water				
California	Seawater Ambient temperture	10 m^3 (few thousand gallons)	Discharge once per week	[188]
California	Seawater Chlorine disinfectant	80 m^3/d	Intermittent discharge	[190]

*Mixed with 10,500 m3/d cooling water

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VI. SELECTION OF POLLUTANT PARAMETERS

INTRODUCTION

Based on a detailed assessment of the extensive information collected by the Agency in this and in previous studies on the quantities and characteristics of waste discharges from this industry, the following pollutants and pollutant characteristics are of concern and are being considered for first time coverage or for more stringent effluent limitations and standards:

Drilling Fluids

- Free Oil
- Toxicity
- Priority Pollutants
- Oil-Based Drilling Fluids, Diesel Oil
- Oxygen Demand

* Well Treatment Fluids

- Free Oil

Drill Cuttings

- Free Oil
- Oil-Based Drilling Fluids, Diesel Oil
- Oxygen Demand

Produced Water

- Oil and Grease
- Priority Pollutants

* Produced Sand

- Free Oil

* **Deck Drainage**

  - Free Oil

Sanitary Wastes

  - Fecal Coliform (Total Residual Chlorine)
  - Floating Solids

Domestic Wastes

  - Floating Solids

* Additional pollutants may be selected pending additional data collection and analysis.

The following sections provide the rationale utilized to select these parameters.

DRILLING FLUIDS

Free Oil

The term "no discharge of free oil" is being amended in this proposed rulemaking to prohibit the discharge of applicable waste streams that would cause a film or sheen upon or a discoloration of the surface of the receiving water, as determined by the Static Sheen Test. (The Static Sheen Test is described in Appendix A of this document.) This definition differs from that currently specified in 40 CFR 435.11, which requires ". . . that a discharge not cause a film or sheen upon or a discoloration on the surface of the water or adjoining shorelines or cause a sludge or emulsion to be deposited beneath the surface of the water or upon adjoining shorelines." The limitation was originally intended to prohibit the discharge of drilling fluids (as well as drill cuttings and well treatment fluids) that, when discharged, would cause a sheen on the receiving water. The limitation was then extended for final BPT regulations to include deck drainage, and the current definition of the term "no discharge of free oil" was established to be consistent with the oil discharge provisions of Section 311 of the Act. Technically, however, discharged drilling fluids could be considered "sludge." For this reason, the Agency is proposing to amend the current definition by excluding language that prohibits the deposit of sludge beneath the surface of the receiving water. This would allow the discharge of drilling fluids, provided that other effluent limitations are met.

The Static Sheen Test is a proposed method using laboratory procedures performed on site, prior to discharge, for determining whether a particular waste stream will cause a sheen on the receiving water. The existing BPT method of compliance is an after-the-fact determination performed by observing the receiving waters after the discharge has occurred. The proposed method will also eliminate the difficulty of seeing a sheen at night, under icing conditions, and in rough sea conditions. The test is conducted by adding samples of the effluent stream into a container in which the sample is mechanically mixed with a specific proportion of seawater, allowed to stand for a designated period of time, and then viewed for a sheen.

Free oil, oil-based drilling fluids, and diesel oil are all related to the oil content in drilling fluid waste streams and the concentration of priority as well as conventional and nonconventional pollutants present in those oils. The pollutants "free oil," "oil-based drilling fluids," and "diesel oil" are each considered to be "indicators" of specific priority pollutants present in these complex hydrocarbon mixtures used in drilling fluid systems. These pollutants include benzene, toluene, ethylbenzene, naphthalene, and phenanthrene.

Sampling and analysis data demonstrate that when the amount of oil, especially diesel, is reduced in drilling fluid, the concentrations of priority pollutants and the overall toxicity of the fluid generally is reduced. Controlling of the amount and type of oil present in drilling fluids with limitations on the three "indicators" (free oil, oil-based drilling fluids and diesel oil) provides a substantial level of control of the priority pollutants present in drilling fluids.

Toxicity (LC50)

Toxicity tests are used to determine levels of pollutant concentrations which can cause lethal or sublethal effects on organisms, and are categorized as either acute or chronic. Acute toxicity tests involve exposures of 96-hours or less, while chronic toxicity tests involve long-term exposures, usually entire or partial life-cycles. [254]

Acute toxicity tests are used to determine the short-term effects of a chemical or mixture on an organism. Results are generally reported as the concentration at which 50 percent of the organisms are killed (the LC_{50}, or median lethal concentration), or display a defined effect of toxicological importance, such as loss of mobility (the EC_{50} or median effects concentration). The higher the LC_{50} or EC_{50} for a given exposure time, the lower the toxicity of the substance being tested. [254]

Acute toxicity tests can be conducted in static, renewal, or flow-through systems. Static systems involve exposure to a single batch of test solution for the full test period. Renewal systems involve periodically replacing the test solution with new solution of the same concentration. in flow-through systems, the test solution is continuously replaced and excreted metabolites are removed. EPA's proposed protocol for toxicity testing of drilling fluids specifies a static bioassay system (Appendix C of this report). [254]

Chronic toxicity tests evaluate the long-term effects of pollutant exposure on survivability, growth, maturation, and reproduction. The results are generally expressed as a range, with the smaller value the lowest concentration resulting in the prescribed effect, and the larger value the highest concentration not producing the effect. [254]

Chronic tests can be life cycle, partial life cycle, or early life stage. Life cycle testing exposes organisms from embryo or newly-hatched larval stage through at least 24 hours after the hatching of the next generation. Partial life cycle tests expose organisms through part of the life cycle, and are used in situations where the organism takes a long period (e.g., a year or more) to mature. Early life stage testing focuses on the embryonic stage shortly after fertilization through early juvenile development. [254]

Results of research activities show that drilling fluids are toxic to marine organisms at certain concentrations and exposure regimes. Further, drilling fluids can adversely affect animals - especially benthos - through physical contact, by burying, or by altering substrate composition. Drilling fluids also can exert effects by disrupting essential physiological functions of organisms. [240]

The areas where drilling fluids are most likely to cause detectable problems associated with water column toxicity are those with shallow water (i.e., where dispersion is limited) or poorly flushed/low energy areas (i.e., where the amount of muds discharged is large compared to local water flux). Sediment toxicity to benthic organisms, oxygen depletion effects, and physical effects due to deposition also are most likely to be observed in these areas. [254]

When discharges are made from platforms located in open, well-mixed, and relatively deep (>20 m) marine environments, most detectable acute effects will be limited to within several hundred meters of the point of discharge. Based on laboratory-derived effects data, there will be sufficient dilution of the drilling fluids in the water column to minimize acute effects on water column organisms. Benthic organisms within about 300 m of the discharge will be potentially subject to adverse effects caused by burial and chemical toxicity; they may also be susceptible to direct effects or substrate changes for greater distances. Possible exceptions to these generalizations could occur when discharges are near sensitive biological areas, such as coral reefs, or in poorly flushed environments. [240]

Additives such as oils and some of the numerous specialty additives - especially biocides - may greatly increase the toxicity of the drilling fluid. The toxicity is, in part, caused by the presence and concentration of priority pollutants. However, control of the indicator parameters alone (free oil, oil-based drilling fluids, and diesel oil) may not be an effective means of regulating these additives. A toxicity limitation would require that operators consider toxicity in selecting additives and select the less toxic alternative. The limitation would also encourage the use of generic water-based drilling fluids and the use of low-toxicity drilling fluid additives (i.e., product substitution).

The eight generic water-based drilling fluids, whose formulations are presented in Section V of this document, are adequate for virtually all drilling situations and are less toxic than oil-based drilling fluids. In order for a drilling fluid to be discharged, it should be no more toxic than the proposed LC-50 standard as determined with the Drilling Fluids Toxicity Test presented in Appendix C of this document.

The most toxic generic fluid is potassium/polymer mud (see Table V-7 of this document). The imposition of an LC-50 toxicity limitation for all drilling fluids which are to be discharged would allow for use of at least any of the eight generic drilling fluids. Seven of the generic drilling fluids (i.e., all but potassium/polymer mud) could be supplemented with low-toxicity specialty additives and lubricity agents to meet operational requirements, and be able to comply with the LC-50 toxicity limitation prior to discharge. This conclusion is based on the results of a toxicity study (reference 248) in which mud samples were spiked with mineral oil at various concentrations.

Priority Pollutants

The trace metals of interest in drilling fluids include barium, zinc, lead, and chromium. The source of barium in drilling fluids is barite; barite may be contaminated with several metals of interest, including mercury, cadmium, zinc, lead, arsenic, and other substances. However, seawater solubilities for trace metals associated with powdered barite generally result in concentrations below background levels. [254, p. 3-58]

Chromium discharged in drilling fluids is primarily adsorbed on clay and silt particles, although some exists as a free complex with soluble organic compounds. [254, p.3-60]

Dissolved metals tend to form insoluble complexes through adsorption on fine-grained suspended solids and organic matter, both of which are efficient scavengers of trace metals and other contaminants. [240]

Trace metals, adsorbed to clay particles and settling to the bottom, are subjected to different chemical conditions and processes than when suspended in the water column. These sorbed metals can be in a form available to bacteria and other organisms if located at a clay lattice edge or at an adsorption site (Houghton et al., 1981). If the sediments become anoxic, conversion of metals to insoluble sulfides is the most probable reaction, and the metals are then removed from the water column. Environments that experience episodic sediment resuspension favor metal release if reducing conditions existed previously in buried sediments; such current conditions also allow further exposure of organic matter complexes for further reduction and eventual release. [240]

Bioaccumulation of a number of metals from exposure to mud components has been demonstrated in the laboratory and in the field. Laboratory studies have indicated that bioaccumulation has been observed for nearly all metals that have been studied, including barium, chromium, cadmium, lead, strontium, and zinc. Barium and chromium show the most dramatic increases (30- to 300-fold); others are much lower (2- to 25-fold). Data on mercury are conspicuous by their absence. [240, 254]

Field data for either one-well operations or small drilling fluid discharges show that sediment levels were elevated for a variety of metals (barium, chromium, cadmium, mercury, nickel, lead, vanadium, and zinc) in a distance-dependent manner. Bioaccumulation was noted in field-collected organisms for several of these metals, although at relatively low levels (2-to 10 fold compared to organisms collected at reference stations).

Limited laboratory data and field data indicate bioaccumulation levels of metals are low (2-to 10-fold) with the exception of Ba (300-fold) and Cr (36-fold). Depuration is often rapid (within 24 hours) and quantitative (40 to 90 percent of excess metals; inversely related to length of exposure). The available data suggest limited uptake of toxic metals from limited exposure to drilling fluid. This uptake is especially a concern because it has occurred following exposure to substances that would be considered not readily bioavailable based on their physical and/or chemical properties. [266]

There are no laboratory or field data that are adequate to assess the bioaccumulation hazard of organic components of drilling fluids. [254] Bioaccumulation of organics from drilling fluids, in particular those associated with (diesel or mineral) oils added as lubricants, has not been fully studied. [240]

Oil-Based Drilling Fluids, Diesel Oil

There is a general consensus that generic drilling muds with no added diesel oil or mineral oil have relatively low acute, lethal toxicity. However, industry contends that the use of diesel and/or mineral oils as lubricating and spotting agents, at relatively high levels (two to four percent), is necessary for reliable operations. The addition of even small amounts of diesel oil to generic drilling muds cause them to become significantly more toxic. Also, diesel oil has a high, statistically demonstrable correlation to observed toxicity. Diesel oil, either as a component in an oil-based drilling fluid or as an additive to a water-based drilling fluid is an indicator of toxic pollutants. The term indicator as used here is a pollutant, constituent or characteristic that exhibits a correlation with one or more other constituents in the same waste. The objective in regulating an indicator is to control the level(s) of the other constituent(s). The nature of the correlation is positive. That is, when the indicator's level is increased, the other constituents' levels are increased; when the indicator's level is decreased, the other constituents' levels are decreased. Diesel oils have been found to contain such toxic organic pollutants as benzene, toluene, ethylbenzene, naphthalene, and phenanthrene (See Section V of this report).

Oxygen Demand

Dissolved oxygen (DO) is a water quality constituent that, in appropriate concentrations, is essential not only to keep organisms living but also to sustain species reproduction, vigor, and the development of populations. Organisms undergo stress at reduced DO concentrations that decrease their ability to compete and survive under such conditions. For example, reduced DO concentrations have been shown to interfere with fish population through delayed hatching of eggs, reduced size nad vigor of embryos, production of deformities in young, interference with food digestion, acceleration of blood clotting, decreased tolerance to certain toxicants, reduced food efficiency and growth rate,, and reduced maximum sustained swimming speed. Fish food organisms are likewise affected adversely in conditions with suppressed DO. Since most higher marine organisms need a certain amount of oxygen, a total lack of dissolved oxygen or even severely suppressed oxygen levels can kill and eliminate the habitat of these species.

Most wastestreams from oil and gas extraction activities - especially drilling fluids and produced waters - exert a significant and sometimes major oxygen demand. The primary sources are soluble biodegradable hydrocarbons and oxidizable inorganic compounds.

If an ecological system is already subjected to large and varied contaminant inputs, adding further contaminants may cause significant problems, even if the additional load is comparatively small. Areas which are subject to higher loadings from other sources of pollution tend to be the nearshore coastal areas, which include shallow and poorly flushed areas. In addition, the usage of nearshore coastal areas for recreation and commercial fishing is characteristically high, which is yet another reason for concern in assessing potential impacts from these discharges. [254]

Each of the three oxygen demand control parameters selected are discussed below.

Biochemical Oxygen Demand (BOD). Biochemical oxygen demand is a measure of the oxygen consuming capabilities of organic matter in water. The BOD does not in itself cause direct harm to a water system, but it does exert an indirect effect by depressing the oxygen content of the water, depending on dilution and dispersion of wastes in the environment. Sewage and other organic effluents during their processes of decomposition exert a BOD, which can have a catastrophic effect on the ecosystem by depleting the oxygen supply. Conditions are reached frequently where all of the oxygen is used and the continuing decay process results in production of noxious gases such as hydrogen sulfide. Water with a high BOD indicates the presence of decomposing organic matter and subsequent high bacterial counts that degrade its quality and potential uses.

Chemical Oxygen Demand (COD). Chemical oxygen demand provides a measure of the equivalent oxygen required to oxidize the materials present in a wastewater sample, under acid conditions with the aid of a strong chemical oxidant, such as potassium dichromate, and a catalyst (silver sulfate). One major advantage of the COD test is that the results are available normally in less than three hours. Thus, the COD test is a faster test by which to estimate the maximum oxygen demand a waste can exert on a stream. However, one major disadvantage is that the COD test does not differentiate between biodegradable and non-biodegradable organic material. In addition, the presence of inorganic reducing chemicals (sulfides, reducible metallic ions, etc.) and chlorides may interfere with the COD test.

Total Organic Carbon (TOC). Total organic carbon is a measure of the amount of carbon in the organic material in a wastewater sample. The TOC analyzer withdraws a small volume of sample and thermally oxidizes it at 150°C. The water vapor and carbon dioxides from the combustion chamber (where the water vapor is removed) is condensed and sent to an infrared analyzer, where the carbon dioxide is monitored. This carbon dioxide value corresponds to the total inorganic value. Another portion of the same sample is thermally oxidized at 950°C, which converts all the carbonaceous material to carbon dioxide; this carbon dioxide value corresponds to the total carbon value. TOC is determined by subtracting the inorganic carbon (carbonates and water vapor) from the total carbon value.

The recently developed automated carbon analyzer has provided rapid and simple means of determining organic carbon levels in wastewater samples, enhancing the popularity of TOC as a fundamental measure of pollution. The organic carbon determination is free of many of the variables which plague the BOD analyses, yielding more reliable and reproducible data.

WELL TREATMENT FLUIDS

Free Oil

Free oil is a selected pollutant parameter for control of well treatment fluids. This parameter and its environmental impact, are discussed in the drilling fluids section above.

DRILL CUTTINGS

Free Oil

Free oil is a selected pollutant parameter for control of drill cuttings. This parameter and its environmental impact, are discussed in the drilling fluids section above.

Oil-Based Drilling Fluids, Diesel Oil

Oil-based drilling fluids and diesel oil are selected pollutant control parameters for drill cuttings. These parameters, along with their environmental impact, are discussed in the drilling fluids section presented above.

Oxygen Demand

BOD, COD, and TOC are selected oxygen demand parameters for control of drill cuttings. These parameters and their environmental impact, are discussed in the drilling fluids section presented above.

PRODUCED WATER

Oil and Grease

Dissolved or emulsified oil and grease are extracted from water by intimate contact with trichlorotrifluoromethane (Freon). Freon has the ability to dissolve not only oil and grease but also other organic substances. No known solvent will selectively dissolve only oil and grease. Freon will also dissolve sulfur compounds, organic dyes, chlorophyll, unsaturated fats and fatty acids. This method, however, also results in the loss of short-chain hydrocarbons and simple aromatics by volatilization. Significant portions of petroleum distillates from gasoline through No. 2 fuel oil are lost in this process. In addition, heavier residuals of petroleum may contain a significant portion of materials that are not extractable with this solvent. This method is currently utilized to quantify the oil content of produced water discharges.

Oil emulsions may adhere to the gills of fish or coat and destroy algae or other plankton. Deposition of oil in the bottom sediments can inhibit normal benthic growth rates, thus interrupting the aquatic food chain. Soluble and emulsified materials ingested by fish can taint the flesh which can reduce the commercial and recreational value of the fishery. Water soluble components may have toxic effects on fish. The water insoluble hydrocarbons and free floating emulsified oils in a wastewater interferes with oxygen transfer, damages the plummage and coats of water animals and fowl and increase oxygen demand.

Priority Pollutants

In the EPA sampling program of produced water from some 30 platforms in the Gulf of Mexico, benzene, ethylbenzene, naphthalene, phenol, and toluene were detected in all samples collected. Zinc was measured in 65 of the 79 samples at concentrations above the lowest reportable value. The second most frequently detected metal was copper (in 12 of the 79 samples). [174]

Results of the Gulf of Mexico sampling program mentioned above are summarized in Tables VI-1, 2 and 3. Priority pollutants analyzed but not detected in any produced water discharge are listed in Table VI-1. Table VI-2 is an overall summary of sampling results for those priority pollutants detected in the treated effluents. Finally, Table VI-3 is a platform-by-platform distribution of priority pollutants detected in the treated effluents.

Benzene. Benzene is a volatile, colorless, liquid hydrocarbon produced principally from coal tar distillation and from petroleum by catalytic reforming of light naphthas from which it is isolated by distillation or solvent extraction. The data from EPA's produced water sampling programs imply that benzene occurs naturally in hydrocarbon bearing strata in varying amounts. Benzene concentrations in the produced waters sampled ranged from 140 to 12,040 mg/l. [258]

The effects of benzene on several saltwater invertebrate and one fish species have been studied. The results had a high variabil-

TABLE VI-1 [174]

PRIORITY POLLUTANTS ANALYZED BUT NOT DETECTED IN ANY PRODUCED WATER DISCHARGE

Volatile Organics

Acrolein
Acrylonitrile
Bromoform
Carbon Tetrachloride
Chlorodibromomethane
Chloroethane
Chloroform
Dichlorobromomethane
Methyl Bromide
Methyl Chloride
Methylene Chloride
Tetrachloroethylene
Trichloroethylene
Vinyl Chloride
1,1-Dichloroethylene
1,1,1-Trichloroethane
1,1,2-Trichloroethane
1,1,2,2-Tetrachloroethane
1,2-Dichloroethane
1,2-Dichloropropane
1,2-trans-Dichloroethylene
1,3-Dichloropropylene
2-Chloroethyl Vinyl Ether

Semi-Volatile Organics

Acenaphthalene
Benzidine
Bis-(2-Chloroethoxy) Methane
Bis-(2-Chloroisopropyl) Ether
Butyl Benzyl Phthalate
Chrysene
Dimethyl Phthalate
Fluoranthene
Hexachlorobenzene
Hexachlorobutadiene
Hexachloro cyclopentadiene
Hexachloroethane
Ideno (1,2,3-C,D) Pyrene
Isophorene
N-Nitrosodi-N-Propylamine
N-Nitrosodimethylamine
N-Nitrosodiphenylamine
Nitrobenzene
Phenanthrene
Pyrene
1,12-Benzoperylene
1,2-Benzanthralene
1,2-Dichlorobenzene
1,2-Diphenylhydrazine
1,2,4-Trichlorobenzene
1,3-Dichlorobenzene
1,4-Dichlorobenzene
2-Chloronaphthalene
2-Chlorophenol
2-Nitrophenol
2,4-Dichlorophenol
2,4-Dinitrophenol
2,4-Dinitrotoluene
2,4,6-Trichlorophenol
2,6-Dinitrotoluene
3,3'-Dichlorobenzidine
4-Bromphenyl Phenyl Ether
4-Chlorophenyl Phenyl Ether
4-Nitrophenol
4,6-Dinitro-o-Cresol

Metals

Chromium
Silver

TABLE VI-2 (174)

SUMMARY OF PRIORITY POLLUTANTS DETECTED IN THE TREATED EFFLUENTS FROM PRODUCTION PLATFORMS IN THE GULF OF MEXICO

Parameter (1)	Number of Valid (2) Determinations	Number of Times (3) Detected	Number of Platforms Where Detected	Minimum (4) Platform Average (μg/l)	Median (4) Platform Average (μg/l)	Maximum (4) Platform Average (μg/l)
Organics						
Benzene	59	59	30	140	1292	12040
Ethylbenzene	59	59	30	19	98	6010
Naphthalene	59	59	30	26	126	1179
Phenol	58	58	30	65	885	20812
Toluene	59	59	30	104	1068	12541
2,4-Dimethylphenol	56	52	27	4	72	2294
Bis-(2-Ethylhexyl) Phthalate	59	47	27	2	56	649
Di-N-Butyl Phthalate	59	19	13	1	4	157
Fluorene	59	13	9	1	9	21
Diethyl Phthalate	59	12	10	1	2	46
Anthracene	29	3	1	1	1	1
Acenaphthene	59	4	4	2	6	10
Benzo (A) Pyrene	59	3	3	1	8	19
P-Chloro-M-Cresol	59	1	1	43	43	43
Dibenzo (A,H) Anthracene	59	1	1	27	27	27
Chlorobenzene	59	1	1	22	22	22
Di-N-Octyl Phthalate	59	1	1	3	3	3
3,4-Benzofluoranthene	59	1	1	3	3	3
11,12-Benzofluoranthene	59	1	1	3	3	3
Pentachlorophenol	59	1	1	2	2	2
1,1-Dichloroethane	59	1	1	2	2	2
Bis-(2-Chloroethyl) Ether	59	1	1	1	1	1
Metals						
Zinc	53	43	23	27	94	445
Copper	53	10	10	8	24	1455
Nickel	53	3	3	72	138	216
Lead	59	2	2	223	2962	5700
Cadmium	59	1	1	98	98	98

NOTES: (1) Pollutants not listed were never detected
(2) Number of samples which yielded valid analytical results
(3) Concentration above detection limit for organics and above the Lowest Reportable Value (LRV) for metals
(4) Includes other platform averages of platforms where detected

TABLE VI-3 [174]

DISTRIBUTION OF PRIORITY POLLUTANTS DETECTED PLATFORM-BY-PLATFORM IN THE TREATED EFFLUENTS FROM PRODUCTION PLATFORMS IN THE GULF OF MEXICO

Parameter	PLATFORM 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Organics	G	G	O	O	G	G	O	G	G	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O	O
Benzene	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Ethylbenzene	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Naphthalene	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Phenol	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Toluene	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
2,4-Dimethylphenol	X	X	X	X	X	X	X	X	X	X		X	X			X	X	X	X	X	X	X	X	X	X	X	X	X	X	X
Bis-(2-Ethylhexyl) Phthalate	X	X	X	X	X	X		X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X		X	X		X
Di-N-Butyl Phthalate			X					X	X			X		X						X	X	X	X	X	X			X		X
Fluorene		X																	X	X	X		X	X		X	X		X	
Diethyl Phthalate		X		X	X	X								X						X		X		X	X					X
Anthracene		–		–	–		–	–		–	–		–	–	–	–	–	–	–	X	–		–		–	–	–		–	–
Acenaphthene			X	X									X															X		
Benzo (A) Pyrene	X																	X												X
P-Chloro-M-Cresol										X																				
Dibenzo (A,H) Anthracene																							X							
Chlorobenzene	X																													
Di-N-Octyl Phthalate																														X
3,4-Benzofluoranthene																							X							
11,12-Benzofluoranthene																							X							
Pentachlorophenol		X																												
1,1-Dichloroethane				X																										
Bis-(2-Chloroethyl) Ether					X																									
Metals																														
Zinc	X	X	X	X	X	X	X	X	X	X		X	X	X		X	X	X		X	X	X	X	X		–	X	X	–	–
Copper				X							X		X			X	X	X		X		X	X	X		–			–	–
Nickel																						X				–	X	X	–	–
Lead										X									X											
Cadmium																			X											

Legend:
X = Detected In At Least One Effluent Sample
– = No Valid Analytical Determinations for Platform
blank = Not Detected In All Effluent Samples

G = Gas Facility
O = Oil Facility

ity among the invertebrate species with a range of effect concentrations of 17,600 to 924,000 mg/l. The fish species (striped bass) was more sensitive with 96-hour LC_{50} values of 10,900 and 5,100 mg/l. [258]

This data indicates that acute toxicity to saltwater life occurs at concentrations as low as 5,100 mg/l and would occur at lower concentrations among species that are more sensitive than those tested. No definitive data are available on the chronic toxicity of benzene to sensitive saltwater aquatic life, but adverse effects occur at concentrations as low as 700 mg/l with a fish species exposed for 168 days. [258]

In both freshwater and saltwater systems, fish species appear to be more sensitive than invertebrate species. [258]

Ethylbenzene. Ethylbenzene is an alkyl-substituted aromatic compound which has a broad environmental distribution due to its widespread use in a plethora of commercial products and its presence in various petroleum combustion processes. Based on the concentrations measured in produced water, 19 to over 6,000 mg/l, ethylbenzene also appears to occur naturally in hydrocarbon formations. [259]

Studies performed on two saltwater fish and three invertebrate species varied widely with LC_{50} values ranging from 430 to 1,030,000 mg/l. The effect of temperature, salinity and life stage on the toxicity of ethylbenzene to the grass shrimp was studied and all LC_{50} values were within the range of 10,200 to 17,300 mg/l, which indicated that those variables had no significant effect on the 24-hour LC_{50} values. [259]

These studies indicate that acute toxicity to saltwater life occurs at ethylbenzene concentrations as low as 430 mg/l and would occur at lower concentrations among species that are more sensitive than those tested. No data are available on the chronic toxicity of ethylbenzene to sensitive saltwater species. [259]

Naphthalene. Naphthalene is a bicyclic aromatic hydrocarbon with the chemical formula $C_{10}H_8$ and a molecular weight of 128.16. One of the principal uses of naphthalene as a feedstock in the United States is for the synthesis of phthalic anhydride. It has also been used directly as a moth repellent and insecticide as well as an antihelminthic, vermicide and an intestinal antiseptic. Naphthalene is the most abundant single constituent of coal tar and forms the base of many crude oils (Naphthenic Crude). The solubility of naphthalene in seawater varies according to salinity. In seawater of average composition, the solubility of naphthalene is about 33,000 mg/l. Naphthalene is biodegradable to 1,2-dihydro-1,2-dihydroxynaphthalene and ultimately to carbon dioxide and water. Concentrations of naphthalene in produced water ranged from 26 to 1179 mg/l. [260]

The effects of naphthalene on saltwater species have been extensively studied as a result of intense interest in the effects of oil pollution on the marine environment. The most significant data produced indicated a nearly 200 percent increase in the occurrence of gill hyperplasia in mummichog after a 15-day exposure to 2 mg/l (there was a 30 percent occurrence in the controls and a 80 percent occurrence in the test organisms.) All of the fish exposed to 20 mg/l demonstrated necrosis of the tastebuds, a change not observed in any members of the control group. [260]

The saltwater fish and invertebrate species tested were of about similar sensitivity to the freshwater species, with LC_{50} values of 3,800 mg/l for a polychaete and 2,350 mg/l for the grass shrimp. There was an apparently atypical 48-hour value for the Pacific Oyster of 199,000 mg/l. The most critical data are those on the histopathological effects on a high percentage of mummichog exposed to concentrations of naphthalene between 2 and 20 mg/l. [260]

Phenol. Phenol, occasionally referred to as "carbolic acid," is a monohydroxybenzene which is a clear, colorless, hygroscopic, deliquescent, crystalline solid at 25°C. It has the empirical formula C_6H_6O, a molecular weight of 94.11 and a specific gravity of 1.071 at 25°C. Phenol has a water solubility of 6.7g/100 ml at 16°C and is soluble at all proportions in water at 66°C. It is also soluble in relatively non-polar solvents such as benzene, petrolatum, and oils. Phenol has been found in the produced water discharges of all production platforms sampled at concentrations ranging from 65 to almost 21,000 mg/l. [261]

Three saltwater invertebrate and three fish species have been studied as to the acute effects of phenol. LC_{50} values were observed as low as 5,800 ug/l. Histopathological damage was observed in the hard clam at concentrations as low as 100 mg/l. A saltwater fish reacted to concentrations as low as 2,000 mg/l. [261]

No data are available concerning the chronic toxicity of phenol to sensitive saltwater aquatic life. [261]

Toluene. Toluene, also referred to as toluol, methylbenzene, methacide, and phenylmethane, is an aromatic hydrocarbon which is both volatile and flammable. Toluene is a clear, colorless, noncorrosive liquid with a sweet, pungent, benzene-like odor and has the molecular formula C_7H_8, a molecular weight of 92.13 and a density of 0.86694 at 20°C. Toluene was detected in produced water discharges at concentrations ranging from 104 to over 12,000 mg/l. [262]

Acute toxicity tests were performed on a number of saltwater species including the grass shrimp, bag shrimp, mysid shrimp and pacific oyster. A chronic value of 5,000 mg/l has been obtained from an embryo-larval test with the sheepshead minnow in which the observed adverse effect was on hatching and survival. [262]

The available data indicate that acute and chronic toxicity to saltwater aquatic life occurs at concentrations as low as 6,300 and 5,000 mg/l, respectively, and would occur at lower concentrations among species that are more sensitive than those tested. [262]

2,4-dimethylphenol. 2,4-dimethylphenol (2,4-DMP) is a naturally occurring, substituted phenol derived from the cresol fraction of petroleum or coal tars. 2,4-DMP is also known as m-xylenol, 2,4-xylenol or m-4-xylenol, and has the empirical formula $C_8H_{10}O$. 2,4-DMP has a molecular weight of 122.17 and a density of 0.9650 at 20°C. In its normal state it exists as a colorless, crystalline solid. 2,4-DMP is present in most produced water discharges at concentrations ranging from 4 to nearly 2,300 mg/l. [263]

No saltwater organisms have been tested with 2,4-DMP. However, acute toxicity to freshwater aquatic life occurs at concentrations as low as 2,120 mg/l. [263]

Zinc. Zinc is a bluish-white metal with an atomic number of 30 and an atomic weight of 65.38. The chemical behavior of zinc is similar to cadmium, which is directly below it on the periodic table, and is never found free in nature but occurs as a sulfide, oxide or carbonate. Zinc forms complexes with a variety of organic and inorganic liquids and is easily adsorbed on clay minerals, hydrous oxides, and organic matter. The tendency of zinc to be sorbed is affected not only by the nature and concentration of the sorbent but by pH and salinity as well. The concentrations measured in produced water, from 27 to 445 mg/l, indicate a moderately strong geographical/geological dependence, probably a result of weathering of various rock formations during the geological episodes in which the hydrocarbon bearing strata were formed. [264]

Acute toxicity data for zinc are available for 21 species of saltwater invertebrates and represent more than two orders of magnitude difference in sensitivity. Larval mollusks were the most sensitive invertebrates with acute values for an oyster of 310 mg/l and for the hard-shelled clam of 166 mg/l. Acute values for adult mollusks ranged from 2,500 for the blue mussel to 7,700 for the soft-shelled clam. Zinc was acutely toxic to saltwater polychaetes over the range from 900 mg/l for Neanthes arenaceodentata to 55,000 for Nereis diversicolor. The decapod crustaceans had 96-hour LC_{50} values of 175 and 1,000 mg/l for the lobster and crab, respectively. The reported acute values for copepods ranged from 290 mg/l for Acartia tonsa to 4,090 mg/l for Eurytemora affinis. Results from tests with two mysid shrimp showed similar values; 498 mg/l for Mysidopsis bahia and 591 mg/l for Mysidopsis bigelowi. [264]

The data base for saltwater fish contains nine values for three species of fish and three taxonomic families. The acute values range from 2,730 for larval Atlantic silversides to 83,000 for larval mummichog. Saltwater fish were generally more resistant to acute zinc poisoning than saltwater invertebrates, although there were cases of individual overlap. [264]

The only chronic data reported for a saltwater species exposed to zinc are those for the mysid shrimp, Mysidopsis bahia. In this flow-through life cycle test the number of spawns recorded at 231 mg/l was significantly fewer than at 120 mg/l, but the number of spawns at 59 and 120 mg/l was not significantly different from those in the control group. Brood size was significantly reduced at 231 mg/l but not at lower concentrations. Based upon reproductive data, the lower and upper chronic endpoints were 120 and 231 mg/l, respectively, which result in a chronic value of 166 mg/l. [264]

Copper. Copper is a soft heavy metal, atomic number 29, with an atomic weight of 63.54, and a density in elemental form of 8.9 g/cc at 20°C. Copper has two oxidation states: cuprous (Cu(I)) and cupric (Cu(II)). Cuprous copper is unstable in aerated water over the pH range of most natural waters (6 to 8) and will oxidize to the cupric state. Bivalent copper chloride, nitrate, and sulfate are highly soluble in water, whereas basic copper carbonate, cupric hydroxide, oxide, and sulfide will precipitate out of solution or form colloidal suspensions in the presence of excess cupric ion. Cupric ions are also adsorbed by clays, sediments, and organic particulates and form complexes with several inorganic and organic compounds. Due to the complex interactions of copper with numerous other chemical species normally found in natural waters, the amounts of the various copper compounds and complexes that actually exist in solution will depend on the pH, temperature, alkalinity, and the concentrations of bicarbonate, sulfide, and organic ligands. [265]

Copper is ubiquitous in the rocks and minerals of the earth's crust. In nature, copper occurs usually as sulfides and oxides and occasionally as metallic copper. Compounds of copper are more soluble in seawater than in freshwater due to the higher ionic strength of saline waters. Studies also indicate that the distribution of copper species in seawater vary significantly with pH and that $Cu(OH)_2$, $CuCO_3$, and Cu^{+2} would be the dominant species over the entire ambient pH range. The concentration of total copper in produced water in the Gulf of Mexico ranged from 8 to nearly 1,500 mg/l. [265]

Although trace quantities of copper are important nutrients for plant and animal life, slightly higher concentrations have a definite biocidal effect. Acute toxicity studies on saltwater invertebrates include investigations on three phyla: annelids, mollusks, and anthropods (crustaceans). The acute sensitivities of crustaceans ranged from 31 mg/l for Acartia tonsa to 600 mg/l for shore crab, Carcinus maenus. Adult polychaete worm acute values ranged from 77 mg/l to 480 mg/l. The 96-hour LC_{50} for Neanthes arenaceodentata increased from 77 mg/l in a flowing water system to 200 mg/l in the presence of a sandy sediment. Nereis diversicolor exhibited a variable response to salinity over a range of 5 to 34 g/kg with the greatest toxicity occurring at 5g/kg. The lowest reported acute value for the bivalve molluscs was 39 mg/l for the soft-shelled clam, Mya arenaria, and the highest was 560 mg/l for the adult Pacific oyster, Crassostrea gigas. The sensitivity of Mya arenaria to copper varied according to the seasonal temperature, with copper being at least 100 times more toxic at 22°C than at 4°C. [265]

The arthropods (crustaceans) were both the most sensitive invertebrate species tested, with an acute value of 31 mg/l for

Acartia tonsa, and the least sensitive of all animals tested, with an acute value of 600 mg/l for larvae of the shore crab, Carcinus maenus. The sensitivity of field populations of Acartia tonsa to copper was strongly correlated with population density and food ration, whereas cultured Acartia tonsa manifested a reproducible toxicological response to copper through six generations. A study reported that lobster larvae appear to be twice as sensitive to copper as the adults. [265]

The acute values for saltwater fish include data for four species and two different life history stages. Acute toxicity ranged from 28 mg/l for summer flounder embryos, Paralichthys dentatus to 510 mg/l for the Florida pompano, Trachinotus carolinus. The results of the acute tests on the embryos of summer and winter flounder were used because embryos of these species apparently are not resistant to copper and because other acute values are not available for these species. [265]

Studies on the effect of salinity on the toxicity of copper indicate that it is more toxic to adult pompano at 10 g/kg than at 30 g/kg. [265]

The only chronic value reported for a saltwater species was that for the mysid shrimp, Mysidopsis bahia. The chronic toxicity of copper to this saltwater invertebrate was determined in a flow-through life cycle exposure in which the concentrations of copper were measured by atomic absorption spectroscopy. Groups of 20 individuals were reared in each of five copper concentrations (control = 2.9 ± 0.5 mg/l, 24.2 ± 7.0 mg/l, 38.5 ± 6.3 mg/l, 77.4 ± 7.4 mg/l, 140.2 ± 11.8 mg/l) for 46 days at 20°C and 30 g/kg salinity. The biological responses examined included time of appearance of first brood, the number of spawns, mean brood size, and growth. The appearance of embryos in the brood sac was delayed for 6 and 8 days at 77 mg/l and 140 mg/l, respectively. The number of spawns recorded at 77 mg/l was significantly fewer than at 38.5 mg/l. The number of spawns at 24 and 38 mg/l was not significantly different from the control. Brood size was significantly reduced at 77 mg/l but not at lower concentrations, and no effects on growth were detected at any of the copper concentrations. Based upon reproductive data, adverse effects were observed at 38 mg/l, but not at 77 mg/l, resulting in a chronic value of 54 mg/l. [265]

PRODUCED SAND

Free Oil

Free oil is a selected pollutant parameter for control of produced sand. The parameter itself, along with its environmental impact, are discussed above as a drilling fluids' parameter.

DECK DRAINAGE

Free Oil

Free oil is a selected pollutant parameter for control of deck drainage. The parameter itself, along with its environmental impact, are discussed above as a drilling fluids' parameter.

SANITARY WASTES

Fecal Coliform (Total Residual Chlorine)

The concentration of fecal coliform bacteria can serve as an indication of the potential pathogenicity of water resulting from the disposal of human wastes. Fecal coliform levels have been established to protect beneficial water use (recreation and shellfish propagation) in the coastal areas.

The most direct method to determine compliance with specified limits is to measure the fecal coliform levels in the effluent for a period representing a normal cycle of operations. This approach may be applicable to onshore installations; however, for offshore operations the logistics become complex, and simplified methods are desirable.

The presence of specific levels of suspended solids and chlorine residual in an effluent are indicative of corresponding levels of fecal coliforms. In general if suspended solids levels in the effluent are less than 150 mg/l and the chlorine residual is maintained at 1.0 mg/l, the fecal coliform level should be less than 200 per 100 ml. Properly operating biological treatment systems on offshore platforms have effluents containing less than 150 mg/l of suspended solids; therefore, total residual chlorine is selected as a control parameter in lieu of direct fecal coliform monitoring of sanitary waste discharges.

DOMESTIC WASTES

Floating Solids

Floating solids interfere with the aesthetic and recreational character of a water body and its adjacent shoreline and produce objectionable odors. Floating solids is selected as a control parameter for sanitary and domestic wastes emanating from small or intermittently-manned offshore facilities.

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VII. CONTROL AND TREATMENT TECHNOLOGY

INTRODUCTION

This section describes the control and treatment technologies that are available for use in the offshore oil and gas industry for the treatment and disposal of pollutants. Various control and treatment technologies were studied for possible use in this industry. Several of these technologies were rejected since, either data was not available on performance or the technologies were determined to be impractical or technologically infeasible for use by this industry segment.

Current regulations require compliance with the Best Practicable Control Technology Currently Available (BPT) effluent limitations. Table VII-1 presents existing BPT effluent limitations for each of the major waste streams. The 1976 development document [3] describes in detail the basic technologies, treatment effectiveness and analytical data evaluation used to establish BPT effluent guidelines for each of these waste streams. A brief description of the control and treatment technologies used to achieve BPT limitations for each waste stream is presented below.

While control and treatment technologies for all of this industry's waste streams are described in this section, the focus of this development document effort has been on the following major streams:

Drilling Fluids;
Well Treatment Fluids;
Drill Cuttings; and
Produced Water

TABLE VII-1

OFFSHORE OIL AND GAS EXTRACTION INDUSTRY
BPT EFFLUENT LIMITATIONS

Waste Source	Oil & Grease - mg/l		Residual Chlorine - mg/l
	Maximum for any one day	Average of daily values for thirty consecutive days not to exceed	Minimum for any one day
Produced Water	72	48	N/A
Deck Drainage	a	a	N/A
Drilling Fluids	a	a	N/A
Drill Cuttings	a	a	N/A
Well Treatment Fluids	a	a	N/A
Sanitary : M10	N/A	N/A	1(b)
M9IM^{c}	N/A	N/A	N/A
Domestic^{c}	N/A	N/A	N/A

Notes:

a - No discharge of free oil.
b - Minimum of 1 mg/l and maintained as close to this concentration as possible.
c - There shall be no floating solids as a result of the discharge of these wastes.
N/A - Not applicable.
M10 - Offshore facilities continuously manned by ten or more persons.
M9IM - Offshore facilities continuously manned by nine or fewer persons or only intermittently manned by any number of persons.

Control and treatment technologies for produced sand, deck drainage, sanitary wastes, and domestic wastes will be further developed as part of the Agency's plan for investigating the priority pollutant characteristics of these streams.

A discussion of analytical and monitoring techniques used to monitor and enforce effluent guidelines is presented in Section V.

DRILLING FLUIDS

Drilling fluids (muds) serve a number of functions but primarily they serve to maintain well bore integrity and to carry drill cuttings to the surface. During the course of drilling a well, it may become necessary to dispose of varying quantities of a specific mud formula to maintain proper mud formulation, accommodate changing drilling conditions or to perform intermediate and final well construction operations. Disposal practices for offshore oil and gas drilling fluids can be considered for two drilling fluid scenarios.

- o Drilling fluid formulations which do not cause significant damage to the marine environment (generally water based fluids).
- o Drilling fluid formulations which may cause significant damage to the marine environment (oil based fluids and water based fluids that contain highly toxic additives).

Diesel oil is a commonly used drilling fluid additive that imparts a high toxicity to drilling fluids. Diesel oil is added for lubricity purposes and to overcome difficult drilling conditions. Also, certain additives, although typically representing a small portion of a given drilling fluid system, may significantly increase the fluid toxicity.

BPT Technology

BPT requirements address the oil and grease content of this wastestream with use of the following process control practices plus end-of-pipe treatment [3]. Process control equipment and practices for drilling fluids that are commonly used in both offshore and onshore drilling operations include:

1. Accessory circulating equipment such as shaleshakers, agitators, desanders, desilters, mud centrifuges, degassers, and other mud handling equipment.

2. Mud saving and housekeeping equipment such as pipe and kelly wipers, mud saver sub, drill pipe pan, rotary table catch pan, and mud saver box.

3. Recycling of oil based muds.

BPT end-of-pipe treatment technologies are based on existing waste treatment processes currently used by the oil industry in drilling operations.

The BPT effluent limitations for offshore drilling fluids prohibit the discharge of free oil in muds that would cause a sheen upon the receiving water when discharged.

Oil based muds effectively cannot be discharged to surface waters because of the prohibition on discharge of free oil. These muds are to be transported to shore for reuse or disposal in an approved disposal site.

Additional Treatment

Waste management practices which control priority pollutant discharges in drilling fluids include:

- conservation and reuse
- use of low toxicity drilling fluids (product substitution)
- treatment and/or disposal on land

Conservation and Reuse. Since drilling fluids are expensive, the economics of well drilling provide a high incentive for reuse of both toxic and low toxicity drilling fluids. This is particularly true of fluids that have hydrocarbon (diesel or mineral oil) liquid base. However, storage and equipment limitations or mineral on drilling platforms restrict conservation alternatives. Drilling platforms contain equipment which removes drill cuttings from the drilling fluid and the processed fluid is recycled to the well hole. Eventually the drilling fluid becomes contaminated with too many fine particles that the platform equipment cannot remove. The particulates alter drilling fluid characteristics (e.g., viscosity) which makes the fluid unacceptable for continued use.

Examples of reuse practices for contaminated fluids which are economically attractive for oil based muds are:

1. Mud company buys back the used mud which is hauled to shore, processed and re-used.

2. Mud is treated with additional solids-suspending agent and used as a packer fluid.

Use of Low-Toxicity Drilling Fluids. Drilling fluids which are considered to have "low toxicity" are discharged directly to the ocean at depths ranging from just below the surface to near the ocean floor. A discussion of one method for identifying a "low toxicity" drilling fluid follows under product substitution.

Treatment and/or Disposal on Land. Drilling fluids which contain toxic materials can be hauled to shore for treatment and/or disposal in landfills. Treatment may involve removal of fine particles and reclamation of the oil-based fluid for reuse or resale.

Production burners have been used successfully at offshore locations to dispose of whole-oil muds laden with solids. To burn properly, the oil mud and diesel oil must be mixed in such a way that the continuous oil phase can be burned. [274] All hydrocarbons are burned completely and the residue is a fine powder comprised of mud products and fine drilled solids. Current practice is to dispose of most contaminated drilling fluids in controlled land fills without treatment. However, detoxification methods are available which remove the toxic materials from the mud prior to disposal.

Solidification techniques also exist which consist of adding chemicals to the mud which react to form a solid material which can be disposed of. The equipment consists of a specially designed blender to mix the drilling fluids and chemicals and to pump the slurry into the prepared area for solidification. The prepared area can be level farmland that has had the topsoil layer removed and a shallow pit excavated to contain the volume of fluid. [274]

The economics of these two approaches have not been determined and data on the leachability and integrity of the solid material has not been quantified.

Product Substitution. Recent studies have sought to identify drilling fluid formulations and drilling fluid additives which exhibit low toxicity in the ocean environment and which can be discharged directly to marine waters. The Agency has conducted a program to determine the relative toxicity of certain "generic" formulations. These generic formulations would then serve as a basis on which industry and regulatory authorities could plan effective control of drilling fluid discharges. (See Section V - Analytical data on generic drilling fluids, and Section VI - Toxicity criteria for drilling fluids.) As a result, the Agency has designated eight generic water-based drilling formulas that exhibit relatively low toxicity levels. A listing of drilling fluid additives which exhibit relatively low toxicity levels in drilling fluid systems has also been compiled (see listing of generic drilling fluids and additives in Section V). Using these "generic" materials as a base, the acceptability for discharge of other drilling fluids and additives can be evaluated based upon their constituents and/or relative toxicity as determined by established laboratory procedures.

Similarly, the Agency and the oil and gas industry are investigating the use of low-toxicity substitutes for diesel oil. Until recently, little research had been performed to identify materials that could perform the specific functions of diesel oil and also be acceptable for discharge to the marine environment. Low toxicity (e.g., mineral) oils have generally been found to serve as acceptable substitutes for diesel oil in drilling fluids.

Low-toxicity, or mineral, oils are derived from the same type of crude oil from which diesel oil is derived. The significant difference between the two types of oils from an environmental standpoint is the relatively high aromatic hydrocarbon content of diesel oil and relatively low aromatic content of mineral (low-toxicity) oils. The aromatic components of the oils are generally the components that are most toxic to marine life.

The low-toxicity oils are composed of a wide variation of paraffinic/napthenic components with very low-aromatic concentrations. The oils are referred to by various names such as mineral oils, low-toxicity oils, low-aromatic oils, etc. White oils are even more highly refined and purified mineral oils that have even lower (sometimes zero aromatic content). High purity white mineral oils are used in foods, laxatives, cosmetics, etc. Thus, the key attempt to lower the toxicity of hydrocarbon base oils is to lower, remove, or alter the aromatic compounds.

One study measured the percent retention of mineral oil based mud on cuttings from the shale shaker and a single-stage cuttings washer at a offshore Texas well. The findings of the study suggested that mineral oil muds present a reduced environmental risk to the marine ecosystem relative to diesel oil muds. Also, it was concluded that mineral oil muds may be more cost effective by reducing the operational costs of cleaning and disposing of cuttings. [241]

Studies by Bennet [270] and Boyd, [275] show that presently available low-toxicity oils are as much as 30 times less toxic than diesel oil to certain marine organisms. Laboratory results also show that diesel and mineral oil are equally effective as lubricants in freeing stuck pipe. Both additives achieve the same reduction in force required to free a stuck pipe [242].

A variety of mineral and vegetable oil-based products have been developed as alternatives to petroleum hydrocarbons as drilling fluid additives. While these products are in limited use in the U.S., they are used more extensively elsewhere. Field and laboratory tests of operating characteristics and environmental acceptability have been conducted. Tests and trial introductions continue as experience is gained concerning the alternatives' operating characteristics and environmental acceptability. [251]

In testing a low-polymer-aromatic mineral oil substitute for diesel oil in the formulation of an oil-base drilling fluid the following were among the conclusions reached [275]:

1. The low-polynuclear-aromatic oil is an acceptable substitute for diesel oil and is compatible with current market oil mud additives.

2. Emulsion stability, rheological, and filtration control properties are easily maintained.

3. Low-polynuclear-aromatic-oil muds provide substantial improvement in regard to toxicity and "polluting" character when compared to diesel-base muds.

WELL TREATMENT FLUIDS

Well treatment fluids include completion, work over, and packer fluids plus miscellaneous discharges of encasement cement and blow-out prevention (BOP) fluids. Characteristics of these materials and their waste products have been discussed in Sections III and V.

BPT Technology

The current BPT requirement is "no discharge of free oil" to receiving waters.

Well Treatment. Well treatment fluids include chemicals used in acidizing and fracturing operations performed as part of remedial service work on old or new wells. Additionally, the fluids used to "kill" a well so that it can be serviced may create wastes for disposal. Liquids used to kill wells are normally drilling mud, water, or an oil, and can occur as discrete discharges. Spent acid and fracturing fluids usually move through the normal production system and through the produced water treatment system. Therefore, these fluids do not appear as a discrete waste source. However, their presence in the waste treatment system can cause upsets and thus a higher oil content in the discharged water.

Additional Treatment

Water treatment processes are not provided for each well treatment fluid since the fluids usually do not return to surface as a separate discharge. Many well treatment fluids mingle with drilling fluids or produced water and are co-treated with these wastestreams. Some of these materials are basically drilling fluids with special purpose additives which can be reclaimed and reused after processing. Others such as stimulation or fracturing materials are mostly lost to the formation. When a well is turned onto production, the fluid lost to the formation usually appears with the oil or gas and is co-treated with the produced water. This fluid can often cause upsets in the water treatment equipment. Fluid not lost to the formation is saved and re-used because of its high cost.

Acids used in stimulation are usually neutralized by the formation and may return to the surface with oil or gas. This material ends up in the produced water and is treated and disposed of together with the produced water.

DRILL CUTTINGS

Pollutant type and waste management practices for drill cuttings are integrally related to the drilling fluid that was employed. That is, drill cuttings from an oil-base drilling fluid are heavily contaminated with hydrocarbon wastes (diesel or mineral oil). Cuttings resulting from use of a low-toxicity, water-based drilling fluid are considered non-toxic and may be discharged directly.

Drill cuttings are carried to the surface thoroughly mixed in drilling fluid. At the surface, a mud treatment system separates the drill cutting particles from the drilling fluid. A typical mud treatment system contains the following items of equipment:

- Shaleshaker: a vibrating screen through which returning mud is passed for removal of large solids. The standard shaker removes cuttings larger than 440 um while the fine screen shaker removes cuttings larger than 150 um.

- Desander: a cyclone separator which is designed to remove solids larger than 40 to 90 um.

- Desilter: a cyclone separator similar to the desander but designed to remove solids larger than 15-25 um.

- Centrifuge: increases the rate of settling for particles in a drilling fluid and removes particles larger than 3-10 um.

- Mud Cleaner: a desander for a weighted mud. The weighting material (barite) passes through with the mud and the cuttings and fines are separated.

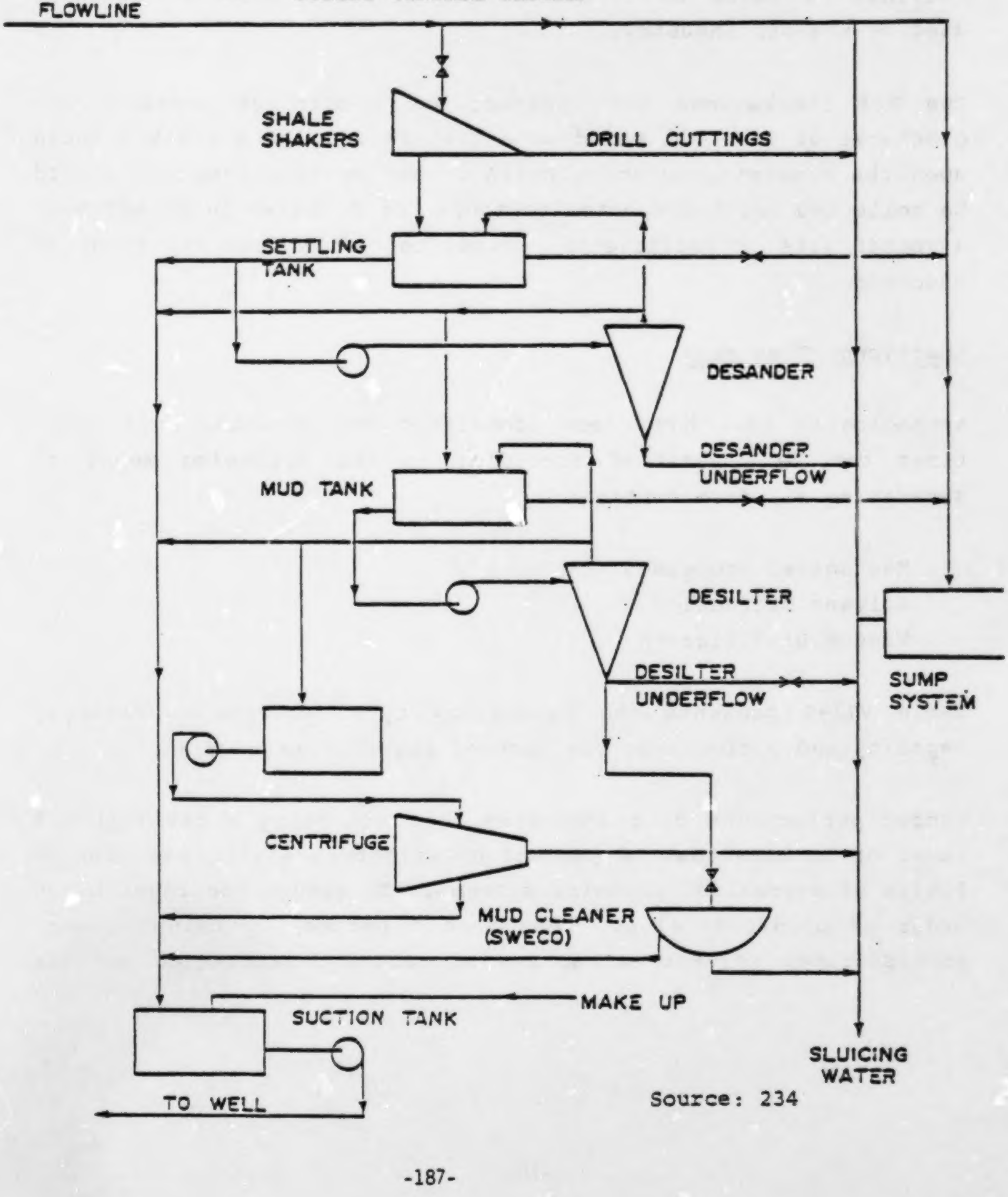
Figure VII-1 is a flow diagram of a typical mud treatment system which shows that seawater may be used to dilute the mud and cuttings prior to disposal.

The drilling fluid is reclaimed and recycled to the well and the cuttings are sorted out for disposal. Discharge from the solids control system contains rock cuttings, sand and clay particles, washwater and residual drilling fluid which has not been removed from the cuttings.

Disposal of cuttings from low-toxicity, water-based drilling fluids is generally by direct discharge to the ocean. Some regulatory authorities stipulate shunting through a vertical pipe to a specified depth below the water surface. Cuttings contaminated with oil are either washed before discharge or transported to approved land disposal sites.

FIGURE VII-1

FLOW DIAGRAM FOR A TYPICAL
SOLIDS CONTROL SYSTEM


FLOWLINE
SHALE SHAKERS
DRILL CUTTINGS
SETTLING TANK
DESANDER
DESANDER UNDERFLOW
MUD TANK
DESILTER
DESILTER UNDERFLOW
SUMP SYSTEM
CENTRIFUGE
MUD CLEANER (SWECO)
MAKE UP
SUCTION TANK
SLUICING WATER
TO WELL

Source: 234

BPT Technology

BPT control technology is directed at the removal of oil and grease using the technologies described above. BPT for drill cuttings is based on treatment and disposal methods presently used by the oil industry.

The BPT limitations for offshore drill cuttings prohibit the discharge of free oil based upon the presence of a visible sheen upon the receiving water. Cuttings that contain free oil should be collected and transported to shore for disposal in an approved disposal site or sufficiently washed to remove free oil prior to discharge.

Additional Treatment

Technologies that have been identified for cleaning drill cuttings can be classified according to the following means of separating oil from cuttings:

Mechanical processes
Solvent Extraction
Vacuum Distillation

Table VII-2 presents the technology type, equipment features, capacity and performance for each of the systems studied.

Vendor performance data indicates that achieving a residual oil level of no more than 10 percent by weight is within the capabilities of mechanical cleaning systems. To reduce the level by an order of magnitude (i.e., less than 1 percent by weight), more sophisticated solvent extraction or vacuum distillation methods

TABLE VII-2

CUTTINGS WASHER TECHNOLOGY

Sheet 1

COMPANY	TYPE OF WASHING TECHNOLOGY	FEATURES	CAPACITY OF UNITS	RESIDUAL OIL ON CUTTINGS	REMARKS
A	Mechanical	Continuous Process, Immersion Method Seawater Wash, Surfactant, 2-800 Gallon Tanks, Eductors, Screen, Centrifuge for Fine Particles	125 Cu. Ft. Per Hour	10% by Volume	
B	(a) Mechanical	Single Stage Centrifuge System for Mineral Oil Based Muds. Agitated Holding Tank, Pump, Centrifuge.	5 Tons Per Hour	7-10% w/w of Dry Cuttings	Used in Norwegian North Sea, for a Union Oil Rig in Louisiana
	(b) Mechanical	Two Stage Centrifuge System for Diesel Oil Based Mud, Wash Tank, Dispersant and Polymer, Vibra-Feeder, Centrifuge, Catch Tank, Pump, Centrifuge.	5-12 Tons Per Hour	3-8.5% w/w of Dry Cuttings	Used in U.K. North Sea
C	(a) Mechanical	Seawater Spray, Flume Discharge, Oil Recovery by Submerged Pumps		Less Than 6% by Weight for Mineral Oil-Based Mud	Used in U.K. North Sea
	(b) Mechanical	Agitated Holding Tank, No Detergent, Pump and Centrifuge	7700 Pounds Per Hour	Less Than 10% by Weight	Used in U.S. Gulf Coast
D	Solvent Extraction	Continuous Process, Diesel Wash Freon Solvent, Extractor Column, Oil-Water Separation, Freon Separation	2500 Pounds Per Hour 7000 Pounds Per Hour	0.2 - 1% w/w	

TABLE VII-2

CUTTINGS WASHER TECHNOLOGY

Sheet 2

COMPANY	TYPE OF WASHING TECHNOLOGY	FEATURES	CAPACITY OF UNITS	RESIDUAL OIL ON CUTTINGS	REMARKS
E	Mechanical	Salt Water Spray, Inclined Trommel for Solid-Liquid Separation	120 Cu. Ft. Per Hour		Used in Gulf of Mexico, Off Coast of California
F	Mechanical	Diesel Wash, Screen for Coarse Particles, Centrifuge for Fine Particles, Sluiced to Seawater	12,500 Pounds Per Hour Peak 25,000 Pounds/Hour	Less Than 10%, With Free Oil 100-500 ppm	Operated in North Sea.
G	Vacuum Distillation	Grinding, Vacuum Distillation Unit, Condenser for Oil and Water, Vacuum Pumps	6 Barrels Per Hour	100-500 ppm	
H	Mechanical	Oil Based Wash Solution, Spray, Screen, Desilting Cones, Oil-Water Separators, Flume Discharge			
J	Mechanical	Wash Tank, Dispersant, Solid Shaker, Desilter, Oil-Water Separator	3-4 Cu. Ft. Per Hour	2%	None
K	Mechanical	Mixing Tank, Cleaning Chemicals, Oil and Sludge Separation, High Pressure Jets.		6-7% by Volume	None

would be required. However, these methods have not been demonstrated, to the Agency's knowledge, in any full-scale field application for any extensive length of time.

Comparison of performance data for the systems studied is complicated by:

- Variations in operating conditions and composition of pollutants.
- Sampling procedures and analytical methods used.
- Historical lack of standardized units of weight or volume to measure performance.

Mechanical Processes. Mechanical systems are most prevalent in California, the Gulf of Mexico and the North Sea. In the mechanical processes, drilling mud is first loosened from the cuttings and then the cuttings are separated from the drilling mud. Drilling mud is loosened from the cuttings either by high pressure sprays or by immersion in a tank with agitation. The spray may be seawater or a wash solution. Drill cuttings may be immersed in seawater, solvent or the wash solution. Sometimes a detergent is used to facilitate washing of the cuttings.

The mixture of drill cuttings, drilling mud and wash solution is sent to a screen for separation of solids and liquids. Liquids carrying fine solids are sometimes sent to desilters or centrifuges for separating the fine solids. The separated oil and additives are sent back to the drilling mud system, wash solutions are recycled and the cleaned cuttings are discharged.

Cleaned cuttings are discharged either directly overboard or through a flume below the water level. In a flume system the cuttings are discharged through the inner pipe of a double pipe system below the water level (See Figure VII-2). In these cases, more oil is separated and the oil rises through the annulus to the seawater level. A submersible pump sends the oil to an oil-water separator for oil recovery. The cleaned cuttings drop to the ocean bottom.

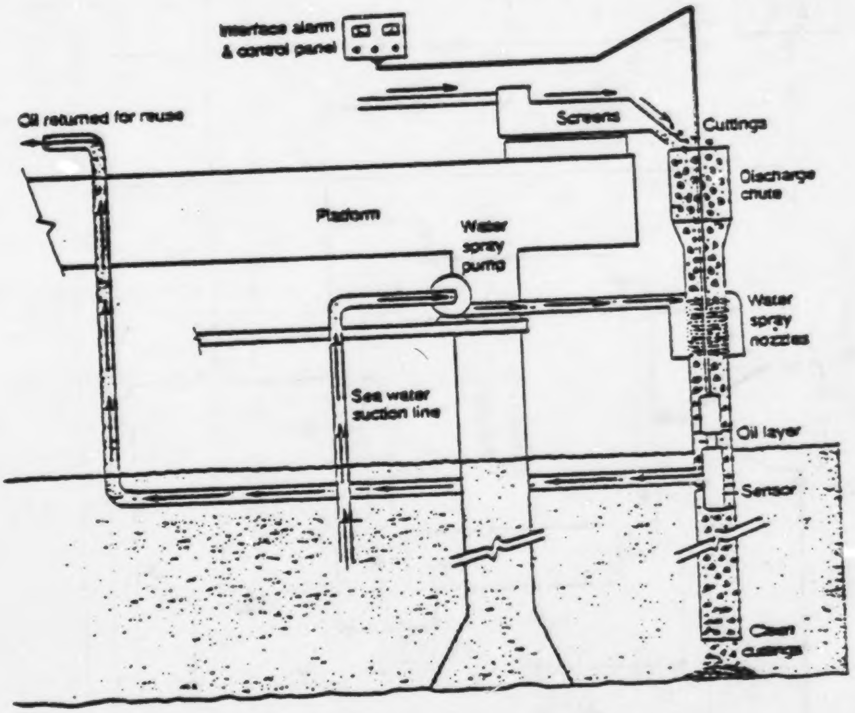
Mechanical systems offered by vendors employ various combinations of the above-mentioned techniques. Capacity of these systems varies from 1.25 to 12 tons per hour. Space requirements are also different for different systems. Some of the subsections are modular and can be made to suit available space. Performance of the cuttings washer system is reported in terms of the residual oil remaining on the cuttings. Most of the vendors claim that the residual oil will be less than 10 percent by weight and there will be no visible sheen resulting from the discharge of the washed cuttings.

Solvent Extraction. One freon extractable cleaning system consists of a raw feed system, a slurry tank where fluidizing oil is mixed with the raw feed, a hydrocyclone, two extraction columns, various solvent and oil separation vessels and a tank where "cleaned mud and cuttings are mixed with sea water prior to discharge." Figure VII-3 is a simplified schematic of the system. The units are available in two sizes: 2500 lbs per hour and 7000 lbs per hour. Performance data is not available for a freon extraction unit in actual, full-scale field operation.

Basically, the mud and cuttings are slurried with oil and fed to a hydrocyclone where some of the oil is separated and is returned

FIGURE VII-2

SCHEMATIC OF A FLUME SYSTEM FOR THE DISCHARGE OF DRILL CUTTINGS


Interface alarm
& control panel
Oil returned for reuse
Screens
Cuttings
Discharge chute
Platform
Water spray pump
Water spray nozzles
Sea water suction line
Oil layer
Sensor
Clean cuttings

Source:247

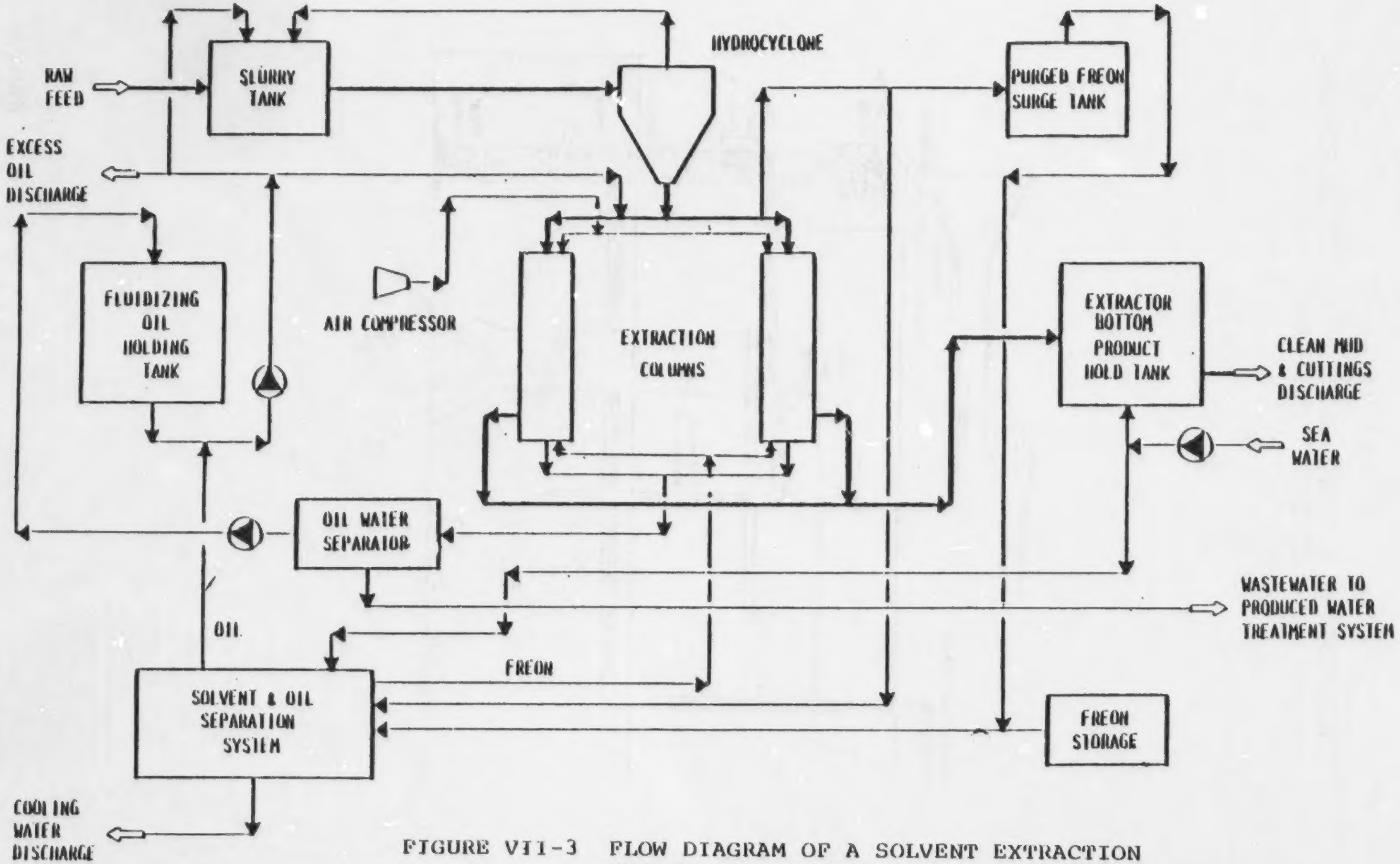

RAW FEED
SLURRY TANK
HYDROCYCLONE
PURGED FREON SURGE TANK
EXCESS OIL DISCHARGE
AIR COMPRESSOR
FLUIDIZING OIL HOLDING TANK
EXTRACTION COLUMNS
EXTRACTOR BOTTOM PRODUCT HOLD TANK
CLEAN MUD & CUTTINGS DISCHARGE
SEA WATER
OIL WATER SEPARATOR
WASTEWATER TO PRODUCED WATER TREATMENT SYSTEM
OIL
FREON
SOLVENT & OIL SEPARATION SYSTEM
FREON STORAGE
COOLING WATER DISCHARGE

FIGURE VII-3 FLOW DIAGRAM OF A SOLVENT EXTRACTION SYSTEM FOR TREATMENT OF DRILL CUTTINGS

Source:247

to the slurry tank. The mud, cuttings and oil exit the hydrocyclone and flow to two extraction columns where freon is added to extract the oil. The "oil-free" mud and cuttings then flow to an extractor bottom product hold tank where water is added to sluice the mud and cuttings to discharge. The oil-laden freon flows from the extractor column to an evaporator, separation column and separator where the oil and freon are separated. The oil phase flows to the fluidizing oil holding tank and the freon is recycled. Excess oil from the mud and cuttings must be periodically bled off and freon must be replaced to account for miscellaneous losses. A small flow of water is generated in the oil-water separator which is assumed to be directed to the produced water treatment system.

Required deck area is approximately 680 sq. ft. for either size unit. The vendor claims that residual oil on the cuttings would not exceed 1 percent by weight.

Vacuum Distillation. Vacuum distillation of cuttings is basically a mini-refinery process. Cuttings are ground to a fine powder, which is fed to a vacuum retort. The retort is heated to a temperature of about 660 degrees F. A two-stage vacuum pump removes the evaporated water, oil and chemicals. The mixed vapor goes through a cyclone for solids separation and finally to a vapor condenser. Condensed liquid (oil, water and some chemicals) is recycled to the mud system. Cleaned cuttings, in the form of a solid residue, are ready for discharge overboard. Long-term operating performance data is not available from drilling contractors using this system. Required deck area, for one vendor's system, is approximately 160 square feet for the processing units and another 16 square feet for the controller units. Capacity of this system is approximately 6 barrels (wet basis) per hour which corresponds to a drilling rate of 50 feet per hour for an 8-1/2 inch diameter hole. Multiple units may be used for processing larger quantities of drill cuttings.

Performance claims by vendors state that the amount of oil remaining on the cuttings is on the order of 100 to 500 ppm (0.01 to 0.05 percent by weight).

PRODUCED WATER

Produced water consists of formation water plus hydrocarbons and chemicals which have been mixed with the formation water during the extraction and separation processes. Section V contains analytical data which characterizes produced water from oil and gas operations. Treatment processes are primarily designed to control the oil and grease and priority pollutant content of this waste stream.

Most states currently allow the discharge of brine to surface, saline water bodies, subject to limitations on the oil and grease content. Other pollutants are generally not regulated. Exceptions are the states of California, Alabama and Mississippi. California has promulgated stringent limits on discharges containing heavy metals effectively precluding the discharge of produced water to any state waters.

BPT Technology

Existing BPT effluent limitations restrict the oil and grease concentrations of produced water to a maximum of 72 mg/l for any one day and an average of 48 mg/l for thirty consecutive days. BPT treatment systems are designed to remove oil and grease from produced water.

BPT process control measures include the following:

- Elimination of the discharge of raw wastewater from free water knockouts or other process equipment.
- Supervised operation and maintenance of oil/water level controls, including sensors and dump valves.
- Redirection or treatment of wastewater or oil discharges from safety valve blow offs and treatment unit by-pass lines.

BPT end-of-pipe treatment can consist of some, or all of the following:

- Equalization (surge tanks, skimmer tanks).
- Solids removal desander (with or w/o sandwasher).
- Chemical addition (feed pumps).
- Oil and/or solids removal.
- Flotation
- Filters
- Plate coalescers
- Gravity tanks
- Subsurface disposal (reinjection).

Because of space limitations on offshore production platforms, oil skimming/equalization, chemical treatment and flotation comprise the most widely used treatment train.

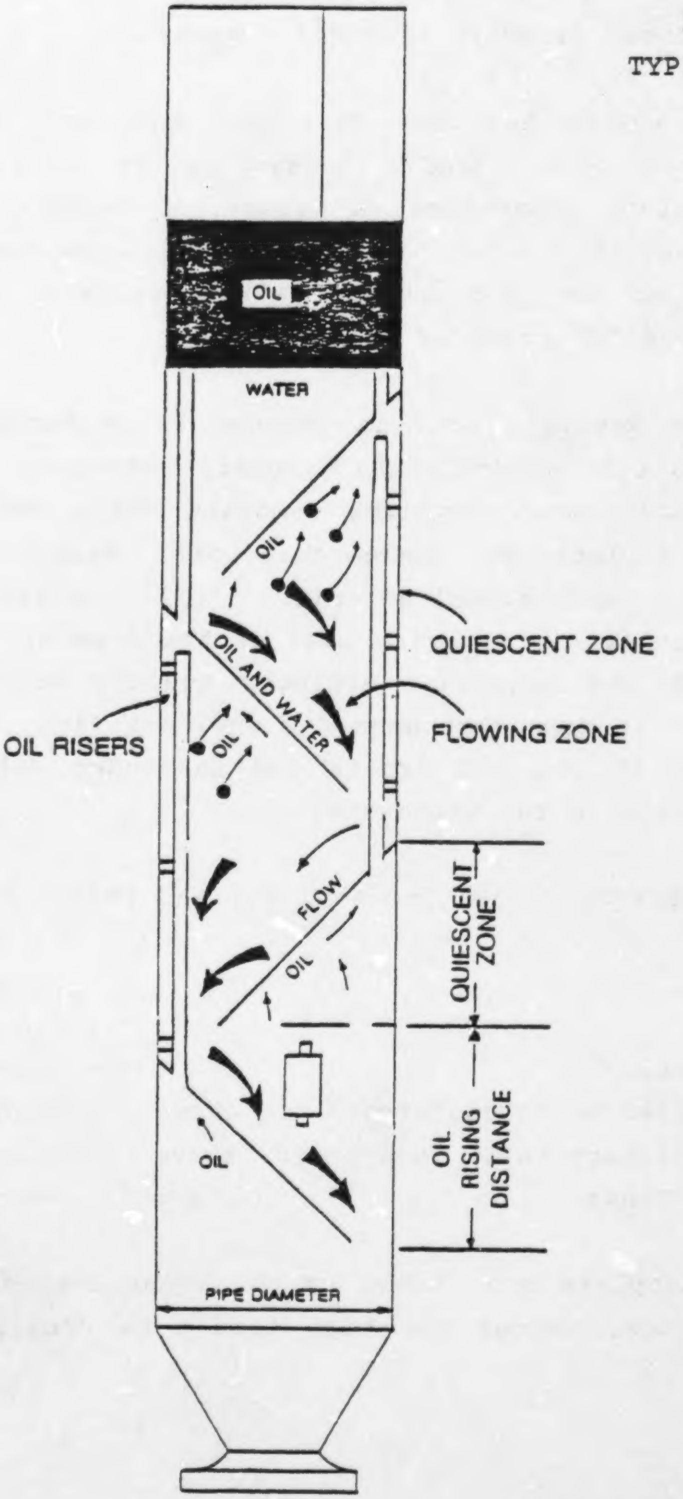
End-of-pipe control technology for offshore treatment of produced water from oil and gas production primarily consists of physical/chemical methods. The type of treatment system selected for a particular facility is dependent upon availability of space, waste characteristics, volumes of waste produced, existing discharge limitations, and other local factors.

Equalization. Surge tanks provide surge volume and primary separation of oil and water before further treatment.

Skim Piles. These are constructed of large diameter pipes containing internal baffled sections and an outlet at the bottom. During the period of no flow, oil will rise to the quiescent areas below the underside of inclined baffle plates where it coalesces (see Figure VII-4). Due to the difference in specific gravity, oil floats upward through oil risers from baffle to baffle. The oil is collected at the surface and removed by a submerged pump. These pumps operate intermittently and will move the separated liquid to a skimming vessel for further treatment [235].

Solids Removal. The fluids produced with oil and gas may contain small amounts of sand which must be removed from lines and vessels. This removal may be accomplished by opening valves to create high fluid velocity which flushes the sand into a collector or a 55-gallon drum. Produced sand may also be removed in cyclone separators.

FIGURE VII-4
TYPICAL SKIM PILE


OIL
WATER
OIL
OIL AND WATER
QUIESCENT ZONE
FLOWING ZONE
OIL RISERS
OIL
FLOW
OIL
QUIESCENT ZONE
OIL RISING DISTANCE
OIL
PIPE DIAMETER

Source: 235

The sand that has been removed is collected and taken to shore for disposal or the oil is removed with a solvent wash and the sand is discharged directly to surface waters.

At least one system has been developed that will mechanically remove oil from produced sand. The sand washer systems consist of a bank of cyclone separators, a classifier vessel, followed by another cyclone. The water passes to an oil water separator, and the sand goes to the sand washer. After treatment, the sand is reported to have "no trace of oil" [255].

Oil and Grease Removal. Oil is present in produced water in a range of sizes from molecular to droplet. Reducing the oil content of produced water involves removing three basic forms of oil: large droplets of coalescable oil, small droplets of emulsified oil and dissolved oil. Oil removal units are generally effective in removing most of the free oil. The removal efficiency and resultant effluent quality achieved by the treatment unit is dependent upon the influent flow, the influent concentrations of oil and grease and suspended solids and the type of chemicals in the wastewater.

Examples of working ranges for some oil and grease removal units are:

Unit	Sizes Removed
Flotation	above 10-20 um
Parallel plate coalescers	above 30-40 um
Proprietary (API) separators	above 6 um
Skim Tanks	above 15 um

Smaller oil droplets are formed by the shear forces encountered in pumps, chokes, valves and high flow rate pipelines. These droplets are stabilized (maintained as small droplets) by surface active agents, fine solids, and high static charges on the droplets [236]. Any operational change that promotes the formation of smaller droplets or the stabilization of small droplets will result in upset conditions and higher contents of oil in the effluent after treatment. Upset conditions can be caused by detergent washdowns in deck drainage entering the treatment unit, unusually high flow volumes caused by heavy rainfall, and equipment failures. Other factors leading to treatment plant upsets are slugs of completion and workover fluids combining with the produced water.

Chemical Treatment. The addition of chemicals to the wastewater stream is an effective means of increasing the efficiency of treatment systems. Chemicals are used to improve the treatment efficiencies of flotation units, plate coalescers, and gravity systems.

Three basic types of chemicals are used for wastewater treatment. Many different formulations of these chemicals have been developed for specific applications. The basic types of chemicals used are:

- Surface Active Agents - These chemicals modify the interfacial tensions between the gas, suspended solids, and liquids. They are also referred to as surfactants, foaming agents, demulsifiers, and emulsion breakers.

- Coagulating Chemicals - Coagulating agents assist the formation of a floc and improve the flotation or settling characteristics of the suspended matter. The most common coagulating agents are aluminum sulfate and ferrous sulfate.

- Polyelectrolytes - These chemicals are long chain, high molecular weight polymers used to assist in the agglomeration of colloidal and extremely fine suspended solid or oil particles.

Surface active agents and polyelectrolytes are the most commonly used chemicals for wastewater treatment. The chemicals are injected into the wastewater upstream of the treatment unit and do not require special premixing units. Serpentine pipes, existing piping arrangements, etc. induce turbulence which disperses polyelectrolytes throughout the wastewater. Recovered oil foam, floc, and suspended particles skimmed from the treatment units are returned to the initial oil/produced water separation system.

Gas Flotation. In a gas flotation unit gas bubbles are released into the body of wastewater to be treated. As the bubbles rise through the liquid, they attach to oil droplets in their path, and the gas and oil rise to the surface where they may be skimmed off as a froth. Two types of gas flotation systems are presently used in oil production; dispersed and dissolved gas flotation. See Figure VII-5.

Dispersed Gas Flotation - These units use specially shaped rotating blades or dispersers to form small gas bubbles which float to the surface with the contacted oil. The gas is drawn down into the water phase through the vortex created by the rotors from a gas blanket maintained above the surface. The rising bubbles contact the oil droplets and come to the surface as a froth, which is then skimmed off. These units are normally arranged as a series of cells, each one operating as outlined above. The wastewater flows from one cell to the next, with oil removal in each cell.

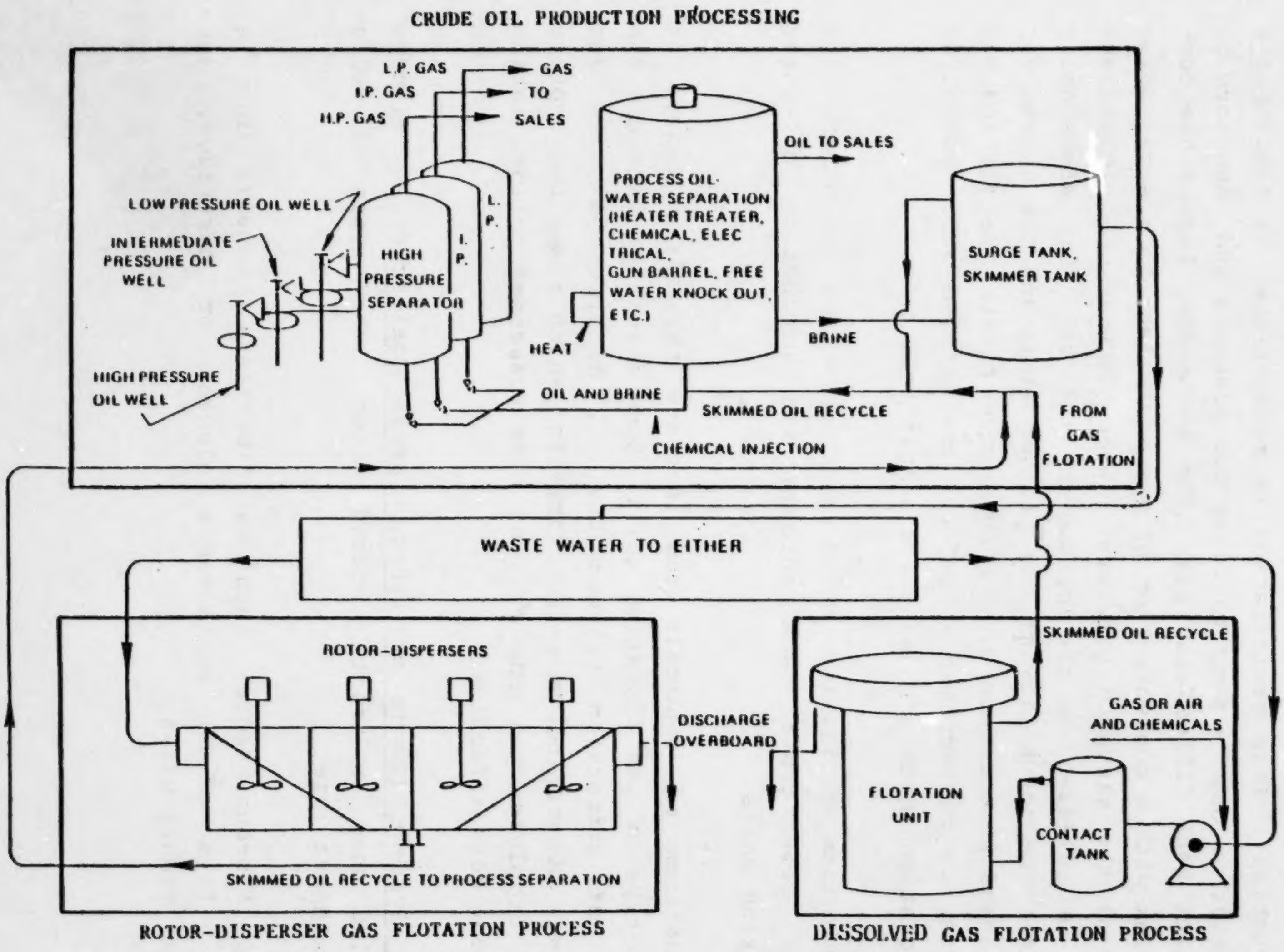

CRUDE OIL PRODUCTION PROCESSING
L.P. GAS
I.P. GAS
H.P. GAS
GAS
TO
SALES
LOW PRESSURE OIL WELL
INTERMEDIATE PRESSURE OIL WELL
HIGH PRESSURE OIL WELL
HIGH PRESSURE SEPARATOR
I. P.
L. P.
HEAT
PROCESS OIL-WATER SEPARATION (HEATER TREATER, CHEMICAL, ELECTRICAL, GUN BARREL, FREE WATER KNOCK OUT, ETC.)
OIL TO SALES
BRINE
SURGE TANK, SKIMMER TANK
OIL AND BRINE
SKIMMED OIL RECYCLE
CHEMICAL INJECTION
FROM GAS FLOTATION
WASTE WATER TO EITHER
ROTOR-DISPERSERS
SKIMMED OIL RECYCLE TO PROCESS SEPARATION
DISCHARGE OVERBOARD
SKIMMED OIL RECYCLE
FLOTATION UNIT
CONTACT TANK
GAS OR AIR AND CHEMICALS
ROTOR-DISPERSER GAS FLOTATION PROCESS
DISSOLVED GAS FLOTATION PROCESS

FIGURE VII-5 FLOW DIAGRAM OF GAS FLOTATION PROCESSES FOR TREATMENT OF PRODUCED WATER

Source:3

Dissolved Gas Flotation - These units differ from dispersed gas flotation because the gas bubbles are created by a change in pressure which lowers the dissolved gas solubility, releasing tiny bubbles. This gasification is accomplished by passing the wastewater through a pump to raise the pressure and then through a contact tank filled with gas. The wastewater leaves the contact tank with a concentration of gas equivalent to the gas solubility at the elevated pressure. When the recycled (gasified) water is released in the bottom of the cell (at atmospheric pressure) the solubility of the gas decreases and the excess gas is released in the form of microscopic bubbles. The gas and oil then rise to the surface where they are skimmed off. Dissolved gas flotation units are usually a single cell only.

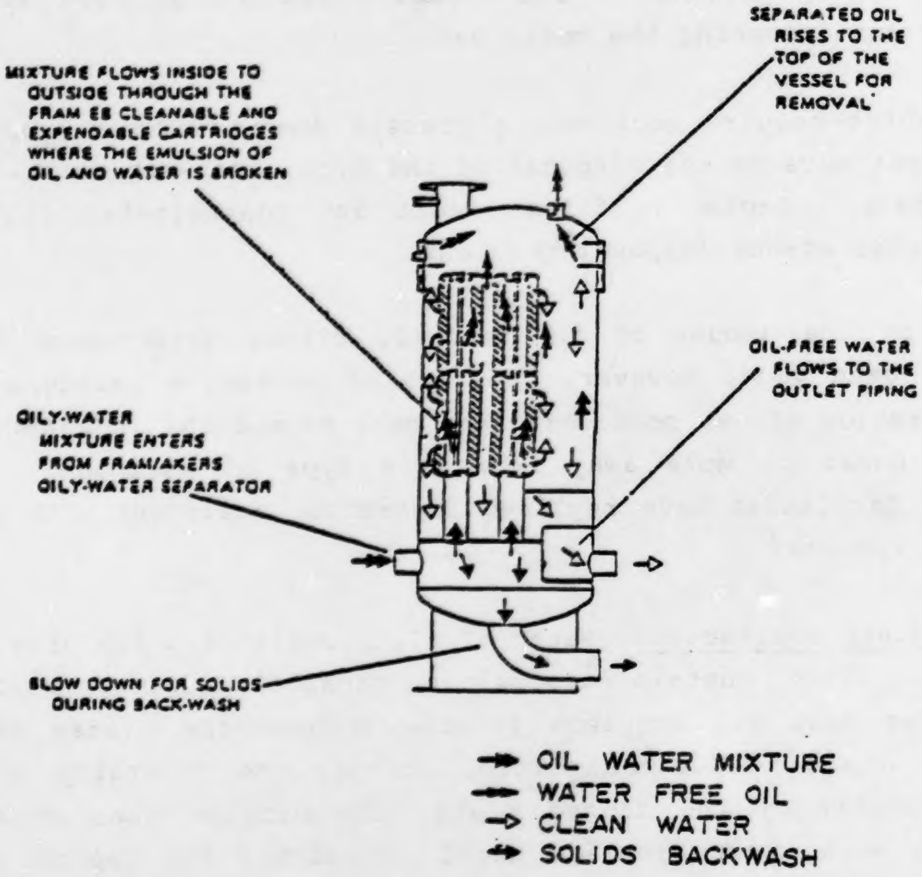
On production facilities it is usual practice to recycle the skimmed oily froth back through the production oil-water separating units.

The addition of chemicals can increase the effectiveness of either type of gas flotation unit. Some chemicals increase the forces of attraction between the oil droplets and the gas bubbles. Others induce a floc formation which eases the capture of oil droplets, gas bubbles, and fine suspended solids, making treatment more effective.

Filter Systems (Loose or Fibrous Media Coalescers). Filters are also used to treat produced water. Two types of media are in general use:

1. Fibrous media, such as fiberglass, usually in the form of a replaceable element or cartridge, see Figure VII-6.

FIGURE VII-6
FIBROUS MEDIA COALESCER


MIXTURE FLOWS INSIDE TO OUTSIDE THROUGH THE FRAM EB CLEANABLE AND EXPENDABLE CARTRIDGES WHERE THE EMULSION OF OIL AND WATER IS BROKEN
SEPARATED OIL RISES TO THE TOP OF THE VESSEL FOR REMOVAL
OIL-FREE WATER FLOWS TO THE OUTLET PIPING
OILY-WATER MIXTURE ENTERS FROM FRAM/AKERS OILY-WATER SEPARATOR
BLOW DOWN FOR SOLIDS DURING BACK-WASH
→ OIL WATER MIXTURE
→ WATER FREE OIL
→ CLEAN WATER
→ SOLIDS BACKWASH

Source: 237

2. Loose media filters, which normally use a bed of granular material such as sand, gravel, and/or crushed coal, see Figure VII-7.

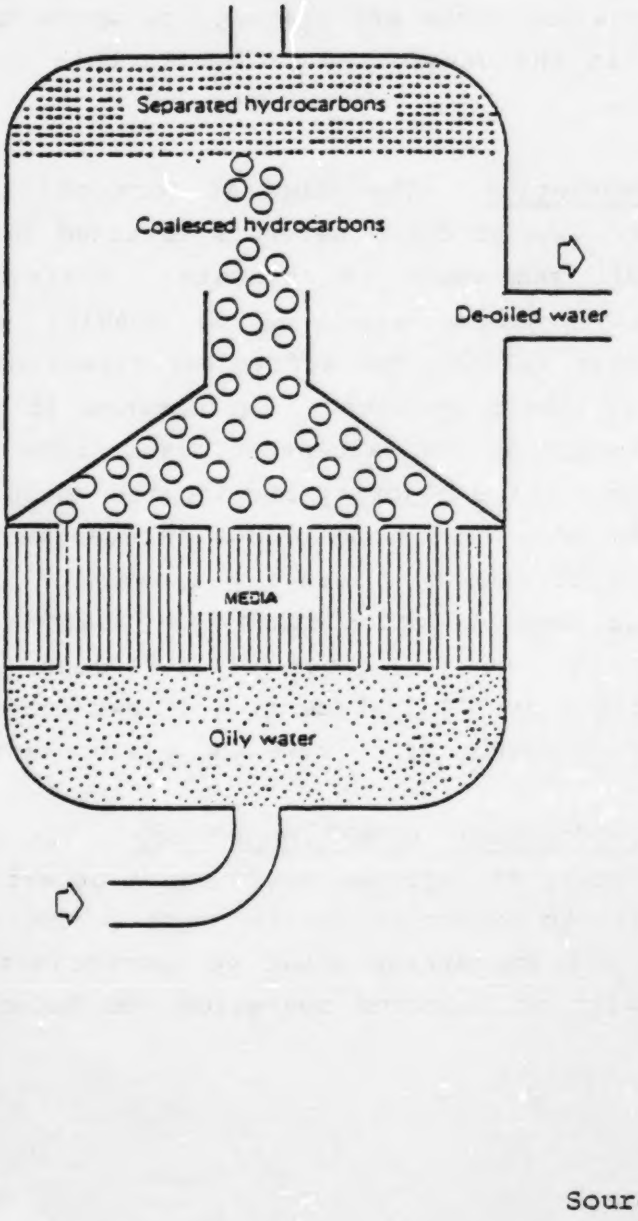
Fibrous media filters may be cleaned by special washing techniques or the elements may simply be disposed of and a new element used. Loose media filters are normally backwashed by forcing water through the bed with the normal direction of flow reversed, or by washing in the normal direction of flow after gasifying and loosening the media bed.

Filters which require backwashing present somewhat of a problem on platforms because the disposal of the dirty backwash water may be difficult. Replacing filter media and contaminated filter elements also create disposal problems.

Measured by the amount of oil removed, filter performance has generally been good; however, problems of excessive maintenance with filtration of raw produced water have caused the industry in the Gulf Coast to move away from this type of equipment. A number of facilities have replaced filtration equipment with gas flotation systems.

Parallel Plate Coalescers. Parallel plate coalescers are gravity separators which contain groups of parallel, tilted plates arranged so that oil droplets passing through the plates need only rise a short distance before striking the underside of a plate. Guided by the tilted plate, the droplet then rises, coalescing with other droplets until it reaches the top of the plate where channels are provided to carry the oil away. The general theory of overall operation of parallel plate coalescers is similar to API gravity oil-water separators. However, the

FIGURE VII-7
GRANULAR MEDIA COALESCER


Separated hydrocarbons
Coalesced hydrocarbons
De-oiled water
MEDIA
Oily water

Source:238

parallel plates reduce the distance that oil droplets must rise in order to be separated; thus unit sizing is much more compact than an API separator. Particles which tend to sink move down along the plates to the bottom of the unit where they are deposited as a sludge and can be periodically drawn off. Particles may become attached (scale) to the surface of the plates requiring periodic shutdown and cleaning of the units.

Where stable emulsions are present, or where the oil droplets are dispersed in the water, separation in this type of unit may not be possible.

Gravity Separation. The simplest form of treatment is gravity separation. The produced water is retained for a sufficient time for the oil and water to separate. Tanks, ponds, pits, and, occasionally, barges are used as gravity separation vessels. Large storage volumes for sufficient retention times are characteristic of these systems. Performance is dependent upon the characteristics of the wastewater, water flow rate, and availability of space. The majority are located onshore and have limited application on offshore platforms because of space limitations. While total treatment by gravity separation requires large containers and long retention times, any treatment system can benefit from even short periods of quiescent retention prior to further treatment. This retention allows some gravity separation and dampens surges in flow rate and oil content.

Improved Performance of BPT Technology. EPA evaluated the costs and feasibility of improved performance of existing BPT treatment technologies to determine whether more stringent effluent limitations for oil and grease would be appropriate. This technology would consist of improved operation and maintenance of existing

BPT treatment equipment (e.g., gas flotation, coalescers, gravity oil separation), more operator attention to treatment system operation, and possibly resizing of certain treatment system components for better treatment efficiency.

Based upon statistical analyses of effluent data from facilities sampled during the Agency's 30-platform survey, EPA determined that an oil and grease effluent limitation of 59 mg/l maximum (i.e., no single sample to exceed) can be achieved through improved performance of BPT technology. This limitation is supported by information presented in the report titled Potential Impact of Proposed EPA BAT/NSPS Standards for Produced Water Discharges From Offshore Oil and Gas Extraction Industry, (January 1984), sponsored by the Offshore Operator's Committee for the Gulf of Mexico. The analysis of information from this study concluded that at least 75 percent of existing offshore operations in the Gulf of Mexico were already achieving oil and grease levels of 59 mg/l (maximum) or less in produced water. In addition, an analysis of produced water effluent data from available discharge monitoring reports (DMR's) was submitted by operators of offshore production facilities in the Gulf of Mexico. This data indicates that at least 60 percent of these facilities are presently achieving an oil and grease concentration of 59 mg/l (maximum) or less in produced water discharges. Thus, improved, or even existing BPT facilities can achieve greater reductions in oil and grease than that currently required for BPT.

Additional Treatment

Various technologies for the control of priority pollutants contained in produced water were studied. These technologies included zero discharge (reinjection or evaporation), biological treatment, chemical precipitation, filtration and activated carbon adsorption. The following discussion outlines the techniques and design considerations involved in the selection and possible application of these technologies to the offshore oil and gas industry.

Reinjection of Produced Waters (Zero Discharge). Disposal of produced water by reinjecting it into the subsurface geological strata can serve a number of purposes:

- Provide zero discharge of wastewater pollutants to surface waters.
- Increase hydrocarbon recovery by flooding or pressurizing the oil bearing strata.
- Stabilize (support) geological formations which settle during oil and gas extraction (a significant problem for onshore and some offshore well fields).

Onshore produced water reinjection is a well-established practice used for most produced water disposal.

In Texas, the largest oil-producing state in the United States, more than 99 percent of all produced water generated onshore is presently reinjected. In Louisiana and California, the corresponding figures are 65 percent and 58 percent, respectively.

Most of the offshore produced water in California waters is presently reinjected. During 1978, predominantly at onshore or man-made island installations in California, this amounted to almost 400 million barrels of produced water.

Since geological conditions and technology will be essentially the same for new sources, reinjection is considered to be demonstrated and technically feasible for the disposal of produced water for facilities off the California coast.

In the Gulf of Mexico, most produced water from offshore platforms receives BPT treatment and is discharged overboard. Onshore reinjection experience in Texas and Louisiana has shown that the regional geology is particularly well suited for the reinjection of produced waters. Also, geological formations are similar and thus produced water reinjection conditions are essentially the same offshore and onshore.

Additional examples of injection are found in Alaska. Waterflooding is employed at a majority of the platforms in Cook Inlet. [272] Also, reinjection of produced waters is the proposed means of disposal at the Endicott Project (Beaufort Sea). [273]

Reinjection of produced water is considered to be demonstrated and technically feasible for the disposal of produced water for facilities in the Gulf of Mexico and in Alaskan waters.

Design Conditions. Many of the requirements in the planning, design and operation of a produced water reinjection system are the same whether the location is onshore or offshore. These include important design considerations such as selection of a receiving formation, preparation of an injection well, and choice of equipment and materials. Significant operational parameters include scaling, corrosion, incompatibility with receiving stratum and bacterial fouling.

Pretreatment of produced water may be necessary to prevent scaling, corrosion, precipitation, and fouling from solids and bacterial slimes. Corrosion and deposits lead to decreased capacity in the equipment and to plugging in the underground formation. One method to overcome this problem is to increase reinjection pressures. However, injection pressure is a regulated parameter in most states, because excessive injection pressure may fracture the receiving formation causing the escape of produced water into freshwater or other mineral bearing formations.

Availability of Disposal Formations - Reinjection of produced water from new sources in the Gulf of Mexico depends upon the availability of suitable disposal formations offshore. Initially, there will be little demand for produced waters as reinjection fluids to enhance recovery. The produced water would be reinjected for disposal purposes only. The onshore reinjection experience in Texas and Louisiana has shown that the regional geology is particularly well-suited for the injection of produced water. Suitable disposal formations are generally available in the production leases. Since in the Gulf region, the geological conditions are essentially the same offshore and onshore, it is concluded that suitable disposal formations are available offshore in the Gulf of Mexico. Further, adequate reservoir capacities are available for the reinjection of all produced waters from new sources. It should be noted that, consistent with the onshore experience, there may be instances where a suitable disposal formation may not be available at each and every offshore facility. Reinjection at different offshore locations would be required in these cases.

Pretreatment Technology - Pretreatment in a closed system including, at a minimum, gravity separation, gas flotation and possibly filtration, would be required prior to reinjection in the Gulf of Mexico. This level of pretreatment is generally more complete than the current pretreatment practices for existing sources in the Gulf. However, the space requirements or the reliability of the pretreatment technology pose no additional problems beyond those encountered offshore in California where the same level of pretreatment is currently practiced prior to reinjection.

Other Considerations - Provisions for the reliability of the reinjection system can be made through redundancy in design so that overboard discharge of produced water is not required because of operational problems. These and other considerations, such as the transport and onshore disposal of solids and sludges generated offshore, which are for the most part economic issues because their technical feasibility is not in question.

Conclusion - In view of the above considerations, it is concluded that offshore reinjection is demonstrated and technically feasible as a control or treatment technology for the disposal of produced waters from new source facilities in the Gulf of Mexico.

Receiving Formation - Selection of the receiving formation should be based on geologic as well as hydrologic factors. This is to determine the injection capacity of the formation and the chemical compatibility of the injected produced water and the water within the formation. The important region-wide geologic characteristics of a disposal formation are areal extent and thickness, continuity, and lithological character. This information can be obtained or estimated from core analysis, examination of bit cuttings, drill stem test data, well logs, driller's logs, and injection tests.

The desirable characteristics for a produced water reinjection formation are: an injection zone with adequate permeability, porosity, and thickness; an areal extent sufficient to provide liquid-storage at safe injection pressures and an injection zone that is confined by an overlying consolidated layer which is essentially impermeable to water. There are two common types of intraformation openings: (1) intergranular and (2) solution vugs and fracture channels. Formations with intergranular openings are usually made up of sandstone, limestone, and dolomite formations and often have vugulor or cavity-type porosity. Also, limestone, dolomite, and shale formations may be naturally fractured. Formations with solution vugs and fracture channels are often preferable for produced water disposal because fracture channels are relatively large in comparison to intergranular openings. These larger channels may allow for fluids high in suspended solids to be injected into the receiving formation under minimum pumping pressure with a minimal amount of produced water pretreatment at the surface.

A formation with a large areal extent is desirable for disposal purposes because the fluids within the disposal formation must be displaced to make room for the incoming fluids. An estimate of the areal extent of a formation is best made through a subsurface geological study of the area.

If it is possible to inject water into the aquifer of some oil-or-gas-producing formation, the size of the disposal formation is not too important. Under these circumstances, the reinjected water would displace water from the aquifer into the producing reservoir from which fluids are being produced. Thus, the pressure in the aquifer would only increase in proportion to the amount that water reinjection exceeds fluid withdrawals. Pressure-depleted aquifers of older producing reservoirs are highly desirable as disposal formations.

Selection of Reinjection Well - Whether the objective is enhanced ("secondary") recovery or disposal, a primary requirement for the proper design of a reinjection well is that the produced waters are delivered to the receiving formation without leaking or contaminating fresh water or other mineral bearing formations. The reinjection well may be installed by either drilling a new hole or by converting an existing well. The types of existing wells which may be converted include marginal oil producing wells, plugged and abandoned wells, and wells that were never completed (dry holes). If an existing well is not available for conversion, a new well must be drilled. Moreover, for reinjection from offshore platforms, equipment and storage space must be provided at the facilities.

Since pressure-depleted aquifers of older producing reservoirs are highly reliable receiving formations, conversion of a marginal well to a reinjection well is often a desirable alternative. The cost of conversion of an existing well is also much less costly than drilling a new well.

Following completion of a disposal well, injectivity index and capacity index can measure the effective permeability of the disposal well and disposal formation. The capacity index is defined as barrels of produced water injected divided by the increase in bottom-hole pressure. The value can be obtained by dividing the reinjection flow rate by the difference between the bottom hole pressure at maximum reinjection rate and the static bottom hole pressure. A well taking fluid under vacuum indicates that the formation is capable of fluid reinjection at a higher rate than that being delivered. This is not necessarily an indication of the volumetric capacity of the well or formation.

Injectivity index is similar to capacity index. It is defined as the change in the number of barrels per day of gross liquid injected into a well divided by the corresponding pressure differential between mean injection pressure and mean formation pressure, referring to a specific subsurface datum (usually this is the mean formation depth). A simple plot of injectivity index versus time can indicate when the formation is plugging and that remedial action is necessary. Capacity index tests should be performed periodically (e.g., monthly) on each well to determine any changes in the reinjection capacity.

Materials and Equipment - Design considerations for materials and equipment include:

- Corrosion resistance of injection tubing
- Packing fluid to protect casings
- Corrosion inhibition of well fluids
- Chemical compatibility of materials, fluids and the produced water to be injected.

Scaling - Scales and sludges that are commonly found in produced water disposal systems include: calcium carbonate, magnesium carbonate, calcium sulfate, barium sulfate, strontium sulfate, iron sulfide, iron oxide, and sulfur. Scale and sludge differ in that scale is a deposit formed on surfaces in contact with water, while sludge may be formed in one place and deposited in another.

Scales and sludges are formed when the water chemistry adjusts to equilibrium conditions. Changes in equilibrium are caused by temperature changes, pressure changes, chemical changes, and the mixing of two or more stable but incompatible waters. Scale may form as a result of a chemical reaction between the water, or some impurity in the water, and the pipe. Corrosion products, such as iron oxide or iron sulfide, are scales of this type. Other precipitates, such as sulfur, may form when water with hydrogen sulfide is mixed with water with a high dissolved oxygen content.

Carbonate and sulfate scales can be prevented by using chemical inhibitors containing polyphosphates and polymetaphosphates. Calcium carbonate scale can be removed mechanically, using scrapers, or chemically, using hydrochloric acid.

Incompatibility - Chemical incompatibility of reinjected produced waters with receiving formation fluids can cause precipitation. This condition could also occur if incompatible waters from different reservoirs or surface sources are mixed prior to reinjection. Precipitation damage resulting from incompatible fluids usually takes the form of plugged pore spaces in the reinjection zone. The treatment of produced water to prevent incompatibility consists of reducing the strength of, or removing the reactive element or otherwise altering the nature of the reinjected fluid.

Corrosion - The corrosion of metals, in a produced water disposal system, is usually caused by electrochemical reactions. In this type of reaction an anode (electron donor) and cathode (electron acceptor) must exist in the presence of a electrolyte (ionic solution) and an external circuit. Anodes and cathodes can exist at different points on the steel surfaces with the steel providing the external circuit. Produced water serves as an excellent electrolyte. Thus, an electric circuit can be set up in the unprotected, produced water handling pipelines with iron being oxidized at one portion of the system (cathode) and iron being reduced and corroded away in another portion (anode).

Dissolved oxygen, carbon dioxide and salts are the major agents found in produced water which cause corrosion in injection systems. Bacteria are the "catalysts".

Bacteria Fouling - The presence of bacteria in a system may cause a corrosion or plugging problem. Bacteria in oil field waters may be aerobic (active in presence of oxygen), or anaerobic (active in the absence of oxygen).

Iron bacteria are aerobic and are active in removing iron from water and depositing it in the form of hydrated ferric hydroxide. They are commonly active in fresh waters but are occasionally found in produced water containing oxygen. The slimes that are formed shield the metal surfaces from oxygen and provide an environment for the growth of sulfate reducing bacteria that can corrode metal. Sulfate reducing bacteria are the most common and economically significant of the bacteria found in salt water disposal and injection systems. Sulfate reducing bacteria are anaerobic and have the ability to convert sulfate to sulfide. Sulfate reducers are most active in neutral to mildly acidic waters, are frequently found under slime deposits, and are most prolific under corrosion products, tank bottoms, filters, oil water interfaces, and dead water areas, such as joints, crevices, and cracks in cement linings. Sulfate reducers may also exist naturally in some oil and water producing strata.

Control of aerobic bacteria is generally accomplished by treatment with an organic biocide or chlorine. It should be mentioned, however, that in a closed system chlorine would not be used because it is an oxidizing agent. Aerobic bacteria, or slime formers, can grow in sufficient numbers to cause significant well plugging. [216]

Remedial Measures - Examples of remedial measures which may be employed to restore the receptibility of a reinjecting formation are:

- acidizing
- hydraulic fracturing
- sand jetting or under reaming
- backflowing
- mechanical cleaning
- treatment with solvents, dispersants and other chemicals.

Section III contains a discussion of these technologies in terms of production methods used for secondary and enhanced recovery.

Pretreatment of Produced Water Prior to Reinjection. Treatment systems may be classified as closed (absence of air) or open (presence of air), although some systems employ features of both.

The closed system prevents produced water/air contact and thus, maintains the chemical equilibrium of the fluid by alleviating the problems arising from oxygen induced corrosion, scaling, and chemical precipitation. In pressure vessels, where oil-water separation and emulsion treating are carried out, a closed system is advantageous. In a closed system, a blanket of natural gas is maintained over the produced water in pipelines and tanks. An oil blanket is not an effective method of preventing oxygen contamination.

In open systems produced water is aerated for two primary purposes. The first purpose is to drive all acid-causing gases (carbon dioxide and hydrogen sulfide) out of solution and reduce corrosion. The second is to oxidize iron and form precipitates which will be retained in settling tanks or on filters, thereby preventing these precipitates from coming out of solution in another part of the system or in the formation. If manganese is present, it will also be oxidized and precipitated. Aeration has one disadvantage in that oxygen is dissolved in the water and will cause corrosion downstream in the system. For this reason, the use of aeration should be carefully controlled.

Pretreatment in a closed system may consist of residual oil removal and filtration prior to reinjection. In an open system, the treatment train may be residual oil removal, aeration and degasification, chemical treatment, including coagulation and settling, and filtration prior to reinjection.

Oil Removal - Primary separation of oil from produced water is usually accomplished in free water knockouts, gun-barrel separators, or heater treaters. The efficiency of these processes is not always sufficient to ensure relatively oil-free water for introduction into the reinjection system. The efficiency of the treatment units removing oil from produced water can be greatly reduced by improper chemical treatment or physical handling of the oil-water mixture before separation. Examples include:

- Overtreatment of producing wells with certain scale inhibitors can stabilize emulsions.
- Certain types of corrosion inhibitors act as emulsifying agents when used applied in batches.
- Certain emulsion breakers can result in very clean oil, but also can create very stable emulsions of oil in water.
- Centrifugal pumps can form oil-in-water emulsions.

Gravity separators are generally used in disposal systems to remove as much residual oil as possible from the produced water. Dissolved gas flotation is a highly efficient method to remove oil from water if an oil-in-water emulsion does not exist. See the previous discussion of these systems in this section.

Sedimentation - Sedimentation processes can be used in open treatment systems prior to reinjection to remove suspended solids. However, unless a chemical coagulant is used, removal of minute, suspended particles called colloids in the size range of 1 to 200 microns cannot be accomplished.

Filtration - This process may be included in both closed and open systems. In closed systems it is the primary means of removing suspended solids, whereas, in open systems, it is used to remove floc particles that were not removed in the sedimentation process. Sand filters or multi-media filters are commonly used in produced water treatment systems.

Industry Injection Practices. Reinjection of produced water onshore is currently practiced extensively in California, Louisiana and Texas. Also, in California waters, produced water from most offshore platforms is presently reinjected after some level of pretreatment. In the Gulf of Mexico, however, the majority of produced water from offshore platforms is treated and discharged to ocean waters. Within the limitations of available data, the following discussion summarizes the industry experience and current practices in the disposal of produced waters in California, Louisiana and Texas.

California - Table VII-3 shows the 1978 produced oil and produced water statistics for the State of California with breakdowns for the onshore and offshore segments of the industry. The total quantity of oil produced onshore during 1978 is 292 million barrels corresponding to an onshore water production of 1.78 billion barrels during the same period. The oil production offshore in California waters amounted to 56 million barrels or about 16 percent of the total production in the state. The total produced waters in the state amounted to 2.10 billion barrels, of which 319 million barrels or about 15 percent were produced offshore. In both onshore and offshore oil production, an average of 6 barrels of water were produced per barrel of oil on a state-wide basis.

Table VII-4 summarizes the produced water disposal practices in California during 1978. About 68 percent of all produced water in the State was reinjected either to enhance the oil recovery

TABLE VII-3

CALIFORNIA OIL PRODUCTION AND PRODUCED WATER STATISTICS (1978) [216]

Location	Oil Production			Water Production	
	Amount (bbl/Year)	No. Of Wells	Average Production (bbl/day/well)	Amount (bbl/Year)	Produced Water Percentage*
Onshore	291,777,000	40,487	20	1,783,742,000	86
Offshore	56,086,000	2,946	52	319,603,000	85
Total	347,863,000	43,433	22	2,103,345,000	86

* Produced water as a percentage of total fluid production

TABLE VII-4

CALIFORNIA PRODUCED WATER DISPOSAL PRACTICES (1978) [216]

Location	Amount of Produced Water (bbl/Year)	Amounts of Produced Brine Injected				Amount Disposed of by Other Means (bbl/year)
		For Enhanced Recovery by Waterflooding	For Enhanced Recovery By Pressurizing	For Disposal	Total Amount	
Onshore	1,783,742,000	642,565,000	1,361,000	392,154,000	1,036,080,000	747,662,000[1]
Offshore	319,603,000	387,063,000	-	5,084,000	392,147,000[2]	-
Total	2,103,345,000	1,029,628,000	1,361,000	397,238,000	1,428,227,000	675,118,000[3]

1 - This amount is disposed of by evaporative percolation ponds, or reinjection offshore.

2 - This amount includes 319,603,000 bbls of produced brines plus an additional 72,544,000 bbls of onshore produced waters which are reinjected offshore.

3 - This amount is disposed of by evaporative percolation ponds.

operations or for disposal. In the onshore segment alone, about 58 percent of produced waters were reinjected while the remaining 42 percent were disposed of by other methods (evaporative percolation ponds, or reinjection offshore). In the offshore segment, all of the produced waters were reinjected, mostly for the purpose of enhanced recovery by water flooding. In fact, the demand for offshore water flooding exceeded the total amount of produced waters available through the offshore production of oil. To meet this demand, 72.5 million barrels of water produced onshore was reinjected offshore.

Table VII-5 shows the number of produced water reinjection wells in California in both the onshore and offshore segments. There are a total of more than 2800 reinjection wells in California. More than 80 percent of the total, or about 2300 wells, are used for enhanced recovery by water flooding or pressurizing while the remaining 20 percent, or about 500 wells, are used for disposal only. In the offshore segment alone, there are 375 reinjection wells, of which only 7 are used for disposal while the remaining 368, or more than 98 percent, are used for enhanced recovery purposes. It is clear that, in California waters, reinjection of produced water offshore is presently practiced predominantly to enhance the recovery of oil through water flooding. The usual practice is to convert a marginally producing well, on an offshore platform, to serve as a reinjection well. Due to economic reasons, it is not the usual industry practice to drill a new offshore well for the reinjection of produced water.

Pretreatment prior to offshore reinjection, in California waters, usually includes gravity separation and gas flotation. But the level of pretreatment can range from no treatment to chemical addition, gravity separation, gas flotation and filtration.

TABLE VII-5

CALIFORNIA PRODUCED WATER REINJECTION WELLS (1978) [216]

Location	Number of Reinjection Wells			
	Enhanced Recovery			
	Waterflood	Pressurizing*	Disposal	Total
Onshore	1,882	72	504	2,458
Offshore	367	1	7	375
Total	2,249	73	511	2,833

*Includes gas and air

Treatment systems are mostly of the closed type (air excluded). Injection pressure is a regulated parameter in California so that integrity of the receiving formation can be preserved by avoiding fracturing under excessive pressures.

Chaffee Island Facility - A site visit was made on November 18, 1980 to a California offshore facility to observe operating practices firsthand. The Chaffee Island site, located about two miles off Long Beach, California, was selected because of the utilization of typical produced water pre-treatment and injection equipment.

Chaffee Island is one of four artificial islands owned by the City of Long Beach and operated by THUMS (Texaco, Humble -now EXXON, Union, Mobil, and Shell Oil Companies). Chaffee Island has the capacity to treat and inject about 50,000 barrels of produced water per day.

About 400,000 bbl/month of oil and 300,000 bbl/month of water are produced at the four islands. The produced water is transferred and injected among the four islands according to production requirements.

The produced water treatment system following freewater knockout consists of gravity settling, gas flotation and multi-media filtration (sand plus anthracite) as shown in Figure VII-8. In addition, chemicals are added at various points in the treatment train to enhance treatability. These chemicals include: Tretolite RY 9545 (an emulsion breaker), Visco 3364 (a coagulant aid), and Petrol C-145B (a corrosion inhibitor).

A wastewater sampling program was conducted at Chaffee Island during the period 11-21-80 through 11-24-80. Samples were taken at three points in the treatment train, namely: clarifier influent, dispersed gas flotation effluent and multi-media filter effluent. These points are shown in Figure VII-8. Both composite (24 hour) and grab samples were taken. The samples were analyzed for all priority pollutants, other metals and conventional pollutants. The results of these analyses are shown in Tables VII-6 through VII-8. Priority pollutants not appearing in these tables were not detected in any of the samples.

California Water Quality Standards for Ocean Waters - The Water Quality Control Plan for Ocean Waters of California has limiting concentrations for several metals and phenolic compounds. These limits are:

	Limiting Concentrations, mg/l		
	6-Month Median	Daily Maximum	Instantaneous Maximum
Arsenic	0.008	0.032	0.08
Cadmium	0.003	0.012	0.03
Total Chromium	0.002	0.008	0.02
Copper	0.005	0.020	0.05
Lead	0.008	0.032	0.08
Mercury	0.00014	0.00056	0.0014
Nickel	0.02	0.08	0.2
Silver	0.00045	0.0018	0.0045
Zinc	0.020	0.08	0.2
Cyanide	0.005	0.02	0.05
Phenolic Compounds	0.02	0.12	0.3

A comparison of these limits to the analytical results of Table VII-8 for Chaffee Island (which are assumed to be typical pro-

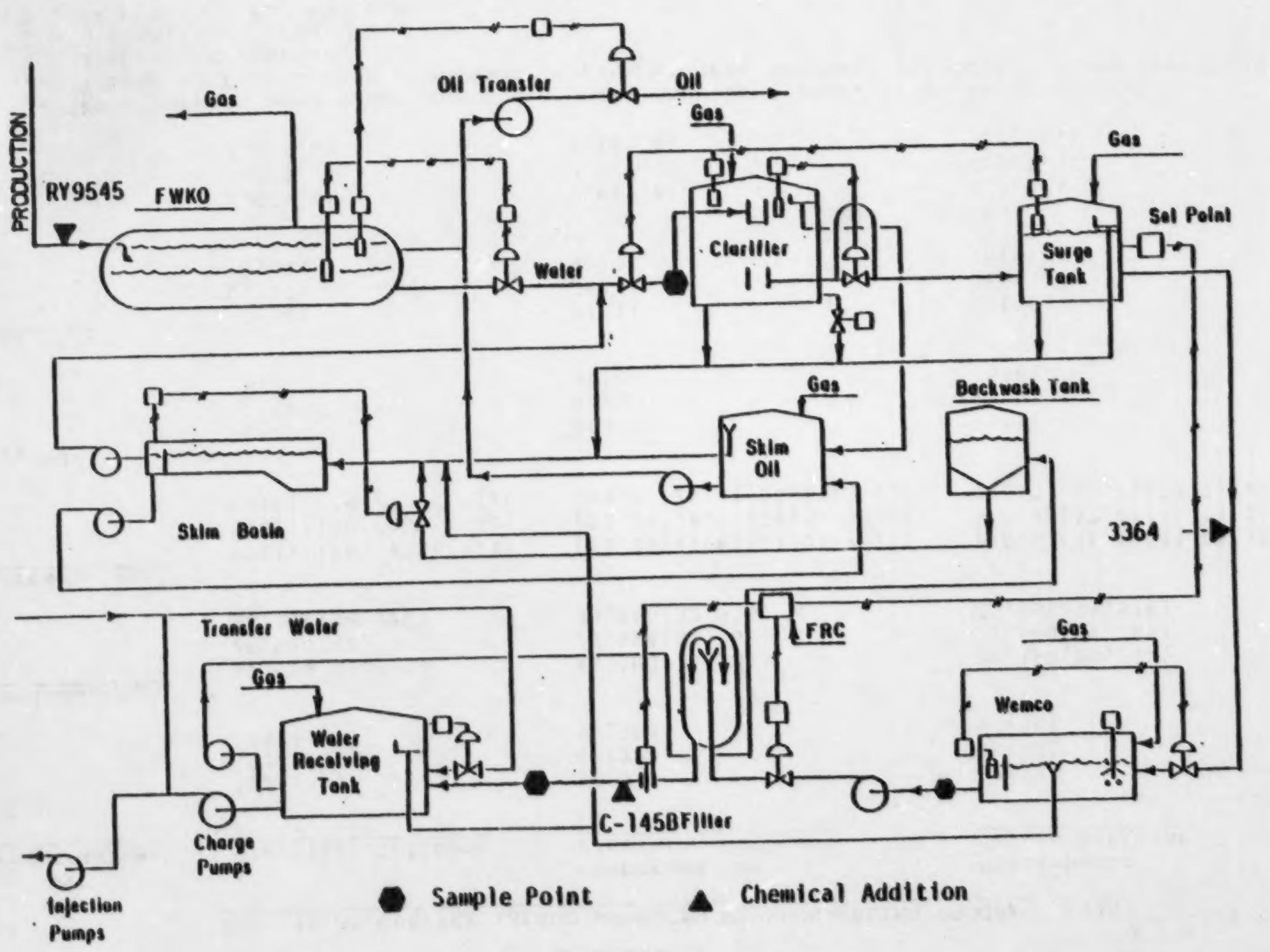

PRODUCTION
RY9545
FWKO
Gas
Oil Transfer
Oil
Water
Gas
Clarifier
Gas
Surge Tank
Set Point
Gas
Skim Oil
Backwash Tank
Skim Basin
3364
Transfer Water
FRC
Gas
Gas
Water Receiving Tank
Wemco
C-145BFilter
Charge Pumps
Injection Pumps
Sample Point
Chemical Addition

FIGURE VII-8 CHAFFEE ISLAND PRODUCED WATER HANDLING SYSTEM-SCHEMATIC FLOW DIAGRAM

Source: 216

TABLE VII-6

RESULTS OF CHAFFEE ISLAND PRODUCED WATER SAMPLING PROGRAM [216]

Parameter, Units	Clarifier Influent	Dispersed Gas Flotation Effluent	Multi-Media Filter Effluent
TSS, mg/l			
Day 1	102(100)	55(74)	60(39)
Day 2	107(103)	68(79)	38(46)
Day 3	85(93)	57(35)	42(86)
Total Solids, mg/l			
Day 1	37,664(39,076)	43,000(36,584)	26,192(26,712)
Day 2	26,980(42,780)	26,994(41,780)	27,700(26,784)
Day 3	43,252(38,980)	33,960(32,856)	25,988(26,348)
Oil & Grease, mg/l			
Day 1	(111)(176)(172)(163)	(13.2)(17.6)(21.3)(18.3)	(16.1)(16.4)(11.0)(19.6)
Day 2	(147)(130)(137)(190)	(21.3)(26.0)(24.3)(33.6)	(19.9)(17.4)(15.7)(20.0)
Day 3	(116)(189)(176)(189)	(24.3)(23.4)(24.6)(26.3)	(22.7)(46.4)(27.7)(23.1)
Cyanide, ug/l			
Day 1	10(7)	5(3)	6(7)
Day 2	4(18)	6(7)	13(7)
Day 3	8(14)	4(12)	8(6)
Phenols, ug/l			
Day 1	1(32)	6(L1)	L1(30)
Day 2	L1(51)	2(L1)	56(L1)
Day 3	8(14)	4(12)	8(6)
pH			
Day 1	6.6(7.0)	7.0(7.0)	7.3(7.3)
Day 2	7.0(7.2)	7.0(7.1)	6.9(7.2)
Day 3	7.2(6.8)	7.1(7.0)	7.2(6.9)

Notes:
1. Four samples were taken every six hours for three days, 11/21/80 - 11/24/80.
2. Values in parentheses represent results of grab samples, all other values represent 24-hour composites.
3. L Signifies "less than."
4. 4APP Method for Phenols

TABLE VII-7

RESULTS OF CHAFFEE ISLAND PRODUCED WATER SAMPLING PROGRAM
ORGANIC PRIORITY POLLUTANTS [216]

Organic Pollutants, µg/l	Clarifier Influent			Dispersed Gas Flotation Effluent			Multi-Media Filter Effluent		
	Day 1	Day 2	Day 3	Day 1	Day 2	Day 3	Day 1	Day 2	Day 3
Phenol	25(27)	24(25)	26(25)	23(22)	20(25)	24(21)	19(24)	20(20)	22(23)
Acenaphthene				*(*)		(*)			
Fluoranthene				*					
Naphthalene	73(49)	56(62)	59(88)	68(67)	74(63)	54(86)	65(85)	65(72)	65(72)
Nitrobenzene								(48)	
N-Nitrosodi-n-propylamine			65						
Bis(2-ethylhexyl) phthalate	19(33)	50(59)	40(26)	(19)	10(*)	*(*)	(*)	29(*)	*(*)
Butyl benzyl phthalate	(89)	17		*				*(*)	
Di-n-butyl phthalate	121(68)	90(71)	52(51)	15(14)	11(*)	*(*)	19(11)	64(*)	*(*)
Diethyl phthalate	231(75)	106(280)	50(48)	19(21)	10(*)	*(*)	32(15)	77(*)	*(*)
Dimethyl phthalate								*	
Anthracene/Phenanthrene	68			10(*)			*(*)	(*)	*(*)
Fluorene				*(*)			*(*)		
Pyrene				*				*	
Benzene	(995)(735) (1001)(878)	(257)(210) (140)(173)	(176)(161) (96)(125)	(902)(1012) (832)(817)	(217)(196) (215)(209)	(178)(194) (183)(196)	(888)(163) (226)(241)	(217)(176) (184)(115)	(187)(173) (180)(169)
Ethylbenzene	(128)(124) (168)(123)	(48)(28) (31)(51)	(41)(28) (10)(10)	(149)(193) (192)(178)	(58)(59) (63)(53)	(29)(30) (27)(24)	(303)(81) (99)(107)	(85)(85) (60)(32)	(65)(59) (65)(49)
Methylene chloride	(148)(139) (140)(140)	(115)(114) (95)(93)	(107)(103) (103)(76)	(346)(76) (78)(74)	(93)(94) (94)(96)	(88)(80) (90)(77)	(77)(110) (109)(112)	(94)(95) (94)(92)	(79)(88) (77)(87)
Methyl chloride			(64)						
Toluene	(678)(561) (881)(641)	(287)(200) (176)(215)	(223)(171) (84)(124)	(747)(864) (846)(779)	(293)(274) (300)(278)	(235)(253) (236)(245)	(840)(231) (304)(338)	(294)(246) (244)(143)	(256)(230) (252)(210)

NOTES:
1. Sampling program performed 11/21/80 - 12/24/80.
2. Values in parenthesis represent results of grab samples; other values represent 24-hour composites.
3. Each composite sample consists of 4 samples taken every six hours.
4. Brine treatment train includes gravity settling (clarifier), dispersed gas flotation, multi-media filtration.
5. Empty space = not detected.

* = Less than 10 µg/l.

TABLE VII-8

RESULTS OF CHAFFEE ISLAND PRODUCED WATER SAMPLING PROGRAM
METALS [216]

	Clarifier Influent			Dispersed Gas Flotation Effluent			Multi-Media Filter Effluent		
Priority Metals, µg/l	Day 1	Day 2	Day 3	Day 1	Day 2	Day 3	Day 1	Day 2	Day 3
Antimony	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)
Arsenic	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)
Beryllium	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)
Cadmium	62 (17)	24 (20)	31 (21)	19 (19)	22 (19)	20 (18)	18 (22)	22 (18)	19 (18)
Chromium	196 (193)	198 (194)	191 (194)	193 (194)	197 (197)	196 (195)	195 (197)	199 (192)	192 (195)
Copper	58 (51)	54 (47)	45 (46)	50 (51)	55 (46)	48 (43)	50 (50)	54 (46)	47 (43)
Lead	384 (356)	373 (335)	341 (315)	349 (354)	336 (320)	336 (326)	345 (345)	360 (311)	337 (321)
Mercury	<1 (<1)	<1 (<1)	<1 (<1)	<1 (<1)	<1 (<1)	<1 (<1)	<1 (<1)	<1 (<1)	<1 (<1)
Nickel	1040 (986)	1060 (963)	943 (955)	995 (1,020)	1030 (994)	1000 (936)	1010 (1020)	1020 (970)	958 (954)
Selenium	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)	<3 (<3)
Silver	<10 (<10)	<10 (<10)	<10 (<10)	<10 (<10)	<10 (<10)	<10 (<10)	<10 (<10)	<10 (<10)	<10 (<10)
Thallium	<100 (<100)	<100 (<100)	<100 (<100	<100 (<100)	<100 (<100)	<100 (<100)	<100 (<100)	<100 (<100)	<100 (<100)
Zinc	211 (171)	239 (204)	257 (187)	163 (162)	182 (166)	202 (172)	164 (153)	177 (155)	158 (162)
Other Metals, µg/l									
Aluminum	592 (479)	501 (436)	408 (411)	485 (472)	498 (464)	464 (395)	479 (469)	523 (425)	433 (394)
Barium (x 10^4)	2.59 (2.69)	2.66 (2.72)	2.64 (2.77	2.63 (2.65)	2.61 (2.75)	2.66 (2.80)	2.63 (2.63)	2.68 (2.71)	2.66 (2.76)
Boron (x 10^4)	3.51 (3.52)	3.61 (3.68)	3.61 (3.69	3.51 (3.59)	3.59 (3.70)	3.62 (3.71)	3.50 (3.59)	3.67 (3.65)	3.60 (3.69)
Calcium (x 10^5)	4.03 (4.01)	3.98 (3.97)	3.86 (4.04	3.94 (3.86)	4.01 (4.04)	3.88 (3.85)	3.91 (3.92)	4.03 (3.89)	3.90 (4.00)
Cobalt	76 (80)	85 (80)	77 (73)	76 (73)	84 (83)	80 (77)	76 (74)	76 (73)	79 (72)
Iron (x 10^3)	4.94 (3.93)	3.91 (4.08)	3.95 (4.02	3.21 (3.80)	3.76 (3.98)	3.77 (3.96)	2.76 (3.21)	2.90 (2.70)	4.41 (4.32)
Magnesium (x 10^5)	3.62 (3.59)	3.56 (3.50)	3.38 (3.52	3.51 (3.47)	3.54 (3.55)	3.41 (3.36)	3.51 (3.48)	3.53 (3.41)	3.44 (3.49)
Manganese	174 (174)	174 (175)	171 (177)	168 (174)	171 (175)	171 (177)	169 (171)	174 (171)	169 (173)
Molybdenum	170 (169)	166 (150)	155 (153)	167 (166)	168 (157)	161 (159)	169 (169)	162 (157)	162 (161)
Sodium (x 10^6)	7.9 (8.0)	7.9 (7.1)	7.2 (7.7)	8 (7.5)	7.8 (7.3)	7.1 (7.2)	7.9 (8.0)	7.5 (7.1)	7.1 (7.6)
Tin	380 (404)	364 (358)	357 (355)	385 (376)	362 (350)	356 (365)	411 (357)	372 (346)	355 (350)
Titanium	<10 (<10)	<10 (<10)	<10 (<10)	<10 (<10)	<10 (<10)	<10 (<10)	<10 (<10)	<10 (<10)	<10 (<10)
Vanadium (x 10^3)	2.32 (2.36)	2.37 (2.39)	2.37 (2.45	2.31 (2.35)	2.35 (2.41)	2.36 (2.46)	2.31 (2.34)	2.39 (2.39)	2.35 (2.45)
Yttrium	101 (84)	99 (82)	72 (73)	91 (89)	98 (83)	88 (68)	91 (91)	98 (82)	81 (74)

NOTES:
1. Sampling program performed 11/21/80 - 11/24/80.
2. Values in parentheses represent results of grab samples; other values represent 24-hour composites.
3. Each composite sample consists of 4 samples taken every six hours.
4. Brine treatment train includes gravity settling (clarifier), dispersed gas flotation, multi-media filtration.

duced water characteristics) explains the need for the widespread injection practices in California ocean waters.

Louisiana - About 60 percent of the total oil production in Louisiana during 1978 was from offshore operations. Table VII-9 summarizes the oil production and produced water statistics for the State of Louisiana during 1978 with breakdowns for the onshore and offshore segments. A summary of the onshore produced water disposal practices is given in Table VII-10. On a statewide basis, about 65 percent of the total onshore produced water is reinjected for disposal purposes only. This is in contrast to the onshore disposal practices in California where reinjection for enhanced recovery is the predominant practice.

In Louisiana formations receiving produced waters are highly porous. In the majority of cases, producers are able to identify acceptable reinjection formations on the production lease. Reinjection depths range from 2,000 to 5,000 feet and wellhead pressures seldom exceed 200 psig. The pretreatment facilities may include primary separation and sedimentation, although reinjection without pretreatment is also practiced.

Offshore produced waters are treated to meet the effluent limitations based on "best practicable control technology currently available" (BPT) and then discharged to ocean waters. Effluent BPT limitations for offshore produced waters are:

Oil and Grease:	Maximum for any one day	72 mg/l
	Average for 30 consecutive days	48 mg/l

Texas - Texas is the largest oil-producing state in the United States. Table VII-11 summarizes the oil production and produced

TABLE VII-9

LOUISIANA OIL PRODUCTION AND PRODUCED WATER STATISTICS [216]

LOCATION	1978 OIL PRODUCTION			1974 Water Production (bbl/year) (1)
	Amount (bbl/year)	Number of Wells	Average Production per Well (bbl/day)	
Onshore	222,241,000	16,747	37	1,068,454,000
Offshore	310,499,000	7,049	121	- (2)
Total	532,740,000	23,796	61	- (2)

(1) 1978 Water production figures are not available. Onshore oil production in Louisiana during 1974 was 307,495,000 barrels or 38 percent higher than 1978 level. Proportionately, onshore 1978 water production would be 772,300,000 barrels.

(2) Actual figures are not available.

TABLE VII-10

DISPOSAL OF PRODUCED WATER ONSHORE IN LOUISIANA

IN 1974 IN BARRELS [216]

DISTRICTS	Total Produced Water Disposed of (1)	To Disposal Wells on Site	Annular Injection on Site (2)	To Pits	To Streams	To Non-Potable Water (3)	To Other Disposal Wells (4)	Trucked or Hauled away for Disposal
Monroe and Shreveport	208,825,000	203,900,000	829,000	621,000	---------	----------	3,475,000	-------
%	100	97.6	0.4	0.3			1.7	
Houma and New Orleans	362,763,000	132,790,000	877,000	16,169,000	49,000	212,858,000	18,000	2,000
%	100	36.6	0.2	4.4	0.01	58.7	0.004	0.0006
Lake Charles and Lafayette	451,128,000	316,550,000	5,974,000	2,265,000	4,804,000	117,366,000	3,392,000	777,000
%	100	70.2	1.3	0.5	1.1	26.0	0.7	0.2
STATE TOTAL	1,022,716,000	653,240,000	7,680,000	19,055,000	4,853,000	330,224,000	6,885,000	779,000
%	100	63.9	0.7	1.9	0.5	32.3	0.7	0.07

(1) Total produced water NOT used for secondary recovery or water flooding.
(2) Water injected between pipe suspended in well bore and the casing or wellbore wall.
(3) Water discharged to tidal estuaries and bays.
(4) Water piped to other disposal wells not on site.

TABLE VII-11

TEXAS OIL PRODUCTION AND PRODUCED WATER STATISTICS [216]

LOCATION	1978 OIL PRODUCTION			1974 WATER PRODUCTION (1)	
	Amount (bbl/year)	Number of Wells	Average Production per Well (bbl/day)	Amount (bbl/year)	Produced Water Percentage (2)
Onshore	1,069,435,000	165,256	18	3,560,900,000	74
Offshore	4,565,000	59	212	16,100,000 (3)	74 (3)
Total	1,074,000,000	165,315	18	3,577,000,000 (3)	74 (3)

(1) Produced water figures for 1978 are not available. Oil production in Texas during 1974 amounted to 1,226,401,000 barrels. On a proportionate basis, produced water during 1978 would be 3,104,000,000 barrels.

(2) Produced water as a percentage of total fluid production

(3) Estimates on a proportionate basis in comparison with onshore amounts.

water statistics for Texas including breakdowns for onshore and offshore segments. In 1978, there were over a billion barrels of oil produced in Texas involving more than 200 of the 254 counties in the state. More than 99 percent of the total oil production in Texas is from onshore wells.

The operation of oil and gas fields in the state is controlled by the Texas Railroad Commission. Regulations prohibit the discharge of any produced water to fresh water streams. Because of the close regulation of the industry and because most fields have secondary oil recovery using water flooding, reinjection of produced waters is extensively practiced. Produced water is also reinjected for disposal on a routine basis. There are currently over 40,000 onshore produced water reinjection wells, of which about 32,000 are used for enhanced recovery purposes. The remaining 8,000 wells reinject produced water for disposal purposes only. More than 99 percent of all produced water from onshore wells in Texas is reinjected onshore. The water produced offshore constitutes less than one percent of the State's total produced water. This offshore produced water is treated to the level of BPT effluent limitations and discharged to ocean waters.

Production wells in Texas range in depth from 100 feet to over 20,000 feet. Disposal wells range in depth from 250 feet to over 10,000 feet although the depth usually does not exceed 2,000 feet. The producing well and the reinjection well are often part of the same lease, with the disposal well located above the producing formation. Thus, in the majority of cases, producers are able to identify acceptable reinjection formations on the production lease.

Pretreatment, prior to reinjection, consists primarily of a gunbarrel separator to remove free oil followed by holding tanks.

The holding tanks serve the dual purpose of providing additional oil separation and surge control for the injection pumps. Reinjection is into single or multiple well systems depending on the quantity of water to be disposed of. Several pre-treatment facilities are often interconnected, and use common reinjection wells. Chemicals are added as required. Biocides are used to control sulfite reduction (that would precipitate metal sulfides). Surfactants are used where greater formation permeability is required.

A discussion of produced water reinjection technology, as currently practiced onshore and offshore, was presented in the preceding sections. Specifically, onshore produced water reinjection practices were discussed in the context of industry experience in Texas, Louisiana, and California. In the offshore segment industry experience in California provided the context for the discussion of produced water reinjection technology.

Evaporation - Zero Discharge - Evaporation of produced water to achieve zero discharge requires ponds with large surface areas located in regions where climatic conditions are such that net evaporation (versus rainfall) occurs. The construction of evaporation ponds on offshore facilities would be impossible due to the large areas required. The piping of the produced water to land-based evaporation ponds is feasible; however, the climatic conditions along the relatively near coastlines are not subject to a net evaporation loss (rainfall is greater than evaporation). Therefore, the use of evaporation for produced water disposal from offshore facilities is considered technically infeasible.

Biological Treatment - Treatment by biological processes may remove the priority pollutants in produced water. However, due to the relatively large treatment vessels required, the use of biological treatment on offshore facilities is impractical. The dissolved solids (measure of brine content) levels in produced water are significantly higher than levels at which any biologically activated treatment system has been used or even tested. Therefore, EPA rejected biological treatment from further consideration for either onshore or offshore for NSPS and BAT because it is, at present, technologically infeasible to implement on a national basis for this industry segment.

Chemical Precipitation - Precipitation is a chemical unit process which converts soluble metallic ions and certain anions to an insoluble form. It is a commonly used treatment technique for removal of heavy metals, phosphorous, and hardness. Chemical precipitation is always followed by a solids separation operation that may include coagulation, sedimentation or filtration to remove the precipitates. Precipitation reactions frequently used for industrial wastewater treatment are one or a combination of the following processes:

- Hydroxide precipitation
- Sulfide precipitation
- Cyanide precipitation
- Carbonate precipitation
- Co-precipitation

Precipitation is effected by the addition of either hydroxides, sulfides or other chemicals at elevated pH values which decreases the solubility of metal ions contained in the wastewater. A precipitate is formed which is removed from the wastewater by mechanical means such as settling, filtration, etc. This process usually produces large amounts of sludges which require dewatering and disposal. If settling is used to remove the precipitates, relatively large treatment vessels are required.

Performance data on chemical precipitation followed by filtration obtained from other industries are summarized in Table VII-12.

The theoretical minimum solubilities for different metals is shown on Figure VII-9. For maximum reductions of metals levels in a solution containing a mixture of metal ions, either an optimum pH level must be determined to minimize the solubilities of the predominant metals or else a treatment train consisting of staged precipitation steps to sequentially treat each predominent metal species must be designed. A complicating factor in the case of produced water is that the solubility of metals generally increases with increasing salinity of the wastewater.

The Agency evaluated the efficacy of hydroxide (lime) and sulfide precipitation, the two most likely types of chemical treatment for the reduction of metals levels in produced water. The Agency's analytical data on produced water prior to treatment indicates that zinc is the only priority pollutant metal found in the majority of samples of produced water discharges. Hydroxide precipitation was determined to effect virtually no removal of zinc from BPT-treated produced water because of the low concentrations of zinc in the BPT effluent. Sulfide precipitation was found to cause potentially serious problems with its use, including generation of sulfide gases and toxicity of the treatment chemicals. In addition, with the use of chemical precipitation, large settling facilities would be required to effect proper treatment and even then the large quantities of generated sludge would have to be disposed. Thus, EPA rejected chemical precipitation from further consideration for NSPS and BAT on a

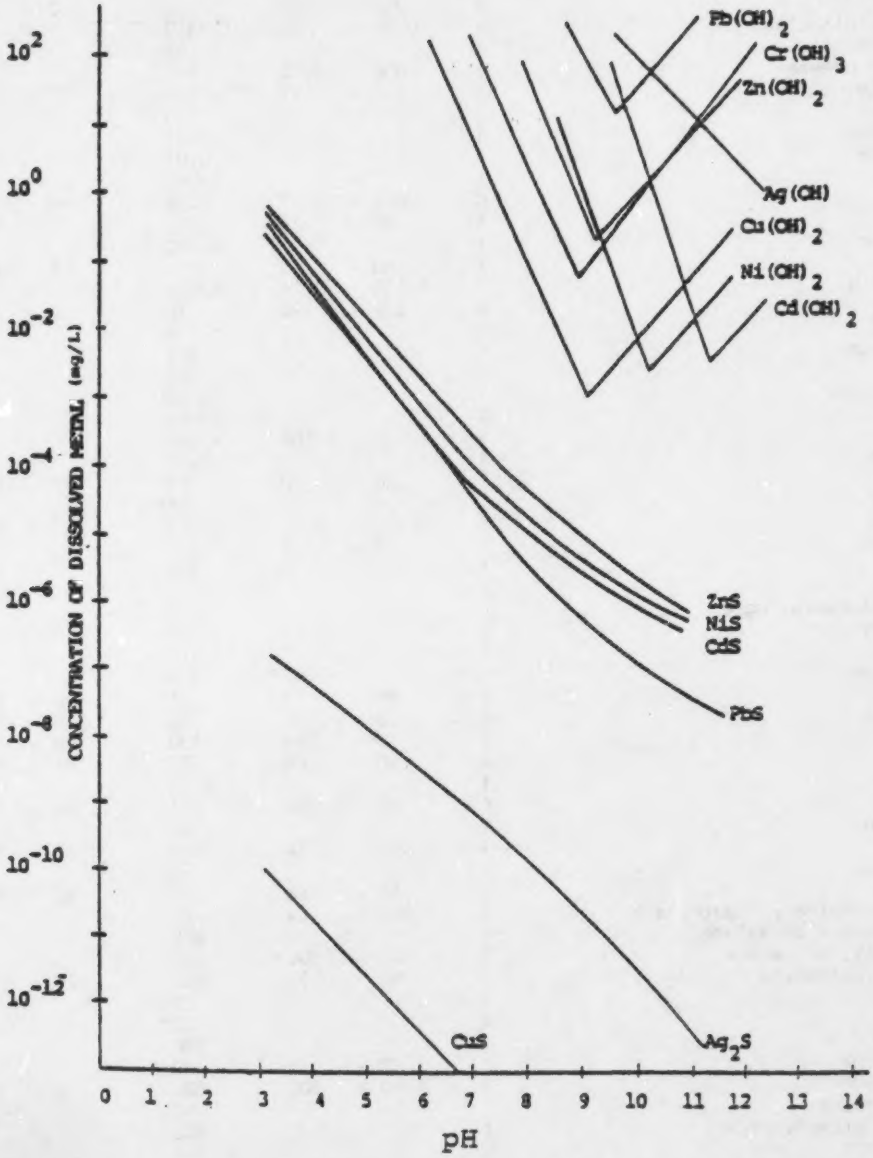
TABLE VII-12

CONTROL TECHNOLOGY SUMMARY FOR CHEMICAL PRECIPITATION WITH FILTRATION FOR SEVERAL INDUSTRIAL GROUPS [217]

	DATA POINTS		EFFLUENT CONCENTRATION		REMOVAL EFFICIENCY, %	
POLLUTANT	PILOT SCALE	FULL SCALE	RANGE	MEDIAN	RANGE	MEDIAN
Classical pollutants, mg/L:						
TSS		6	7.0 - 30	17	0 - 98	77
Total phosphorus		6	0.58 - 52	4.8	9 - 82	41
Total phenols		1		ND		>99
Oil and Grease		5	BDL - 8. 0	BDL		44
Fluoride		6	1.0 - 15	4.2	15 - 54	33
Aluminum		1		1.0		99
Manganese		1		0.02		92
Vanadium		1		0.01		0
Barium		1		0.005		84
Iron		6	0.046 - 4. 7	0.18	45 - >99	95
Tin		5	ND - 0.75	0.06	0 - >99	79
Titanium		1		0.002		50
Gold		5	ND - 40	0.14	8 - >99	50
Palladium		2	0.032 - 0.14	0.086		71
Cyanide, total		4	5.0 - 190	70	0 - 40	24
Calcium		1		110		NM
Magnesium		1		3.7		66
Sodium		1		500		NM
Molybdenum		1		0.80		NM
Cobalt		1		0.005		86
TDS		5	2,756 - 5,700	4,800		NM
Yttrium		1		0.02		0
Osmium		2	ND - ND	ND	99 - >99	>99
Iridium		1		0.08*		NM
Rhodium		2	0.01 - 0.10	0.05	69 - 86	78
Platinum		2	ND - 1.2	0.6		>99
Boron		1		3.0		NM
Toxic pollutants, µg/L:						
Antimony		1		40		NM
Arsenic		1		4.0		33
Beryllium		1		1.0		0
Cadmium		5	ND - 19	6	0 - >99	14
Chromium		5	5.0 - 2,200	18	50 - >99	99
Copper		6	16 - 1,700	780	14 - 99	98
Lead		6	ND - 68	23	81 - >99	92
Mercury		1		0.10		67
Nickel		6	ND - 1,700	205	47 - >99	97
Selenium		1		40		NM
Silver		3	4.5 - 34	9.0	40 - 78	42
Thallium		1		50		0
Zinc		6	10 - 60	15	82 - >99	93
Bis (2-ethylhexyl) phthalate		3	BDL - 84	10		95*
Butyl benzyl phthalate		1		BDL		NM
Di-n-butyl phthalate		3	BDL - BDL	BDL		NM
Diethyl phthalate		3	ND - 75	BDL	25 - >99	62
Phenol		1		13		NM
Benzene		1		1.0*		NM
Toluene		1		BDL		NM
Anthracene		2	ND - 75	ND		NM
Napthalene		2	ND - BDL	BDL		NM
Phenanthrene		1		ND		NM
Carbon Tetrachloride		1		BDL		NM
Chloroform		1		BDL		NM
Methylene chloride		2	ND - 16	8		NM
1,1,1-Trichloroethane		2	0.3 - 1.0	0.7		75
Trichloroethylene		1		0.1*		NM

Blanks indicate data not available.
BDL, below detection limit.
ND, not detected.
NM, not meaningful.
* Approximate value.

FIGURE VII-9



SOLUBILITY OF METAL HYDROXIDES AND SULFIDES AS A FUNCTION OF pH

Source:215

national basis for this industry segment because of operational problems with implementing the technology and non-quantifiable reductions of priority pollutant metals levels in produced water.

Activated Carbon Adsorption - Activated carbon is a material which selectively removes contaminants from wastewater by adsorption. A treatment system utilizing activated carbon must be designed using the proper kinetics for the specific wastewater being treated. In designing an activated carbon system the proper type and amount of activated carbon, the empty bed contact time and the periods between regeneration must be determined. This determination is difficult since the quality of the produced water is variable and can change from well field to well field. It is also dependent upon the characteristics of the oil or gas being produced.

Presently, activated carbon is not utilized in the treatment of produced waters from oil and gas wells. Therefore, the removal efficiencies of activated carbon can only be estimated using data from industries where activated carbon is presently utilized in the treatment of wastewaters. Data is available from the following industries and is summarized on Table VII-13:

- Auto and Other Laundries,
- Electrical and Electronic Components,
- Gum and Wood Chemicals,
- Ore Mining and Dressing,
- Organic Chemicals Manufacturing,
- Petroleum Refining,
- Pulp and Paper Mills,
- Textile Mills, and
- Pesticides Manufacturing.

Generally, activated carbon systems are preceded by treatment systems such as chemical treatment or filtration which will remove suspended solids and other materials that will interfere with adsorption by activated carbon. A review of the pollutant reductions achievable by chemical treatment and filtration was performed and is presented on Table VII-12. This data was compared with that achievable by activated carbon, as shown on Table VII-13.

EPA determined that carbon adsorption is presently technologically infeasible to implement in this industry segment. This is because of the unknown effects that the brine-like nature of produced waters has on the adsorption process, the lack of performance information in either the literature or on a pilot or full-scale basis, and the disproportionately high costs to even attempt to implement this technology on a national basis for this industry segment. Therefore, EPA rejected carbon adsorption from further consideration for NSPS and BAT for produced water.

PRODUCED SAND

The fluids produced with oil and gas may contain small amounts of sand, which must be removed from lines and vessels. This may be accomplished by opening a series of valves in the vessel manifolds that create high fluid velocity around the valve. The sand is then flushed through a drain valve into a collector or a 55-gallon drum. Produced sand may also be removed in cyclone separators when it occurs in appreciable amounts.

The sand that has been removed is collected and taken to shore for disposal; or the oil is removed with a solvent wash and the sand is discharged to surface waters directly.

TABLE VII-13

CONTROL TECHNOLOGY SUMMARY FOR ACTIVATED CARBON ADSORPTION-GRANULAR FOR SEVERAL INDUSTRIAL GROUPS [217]

POLLUTANT	DATA POINTS PILOT SCALE	DATA POINTS FULL SCALE	EFFLUENT CONCENTRATION RANGE	EFFLUENT CONCENTRATION MEDIAN	REMOVAL EFFICIENCY, % RANGE	REMOVAL EFFICIENCY, % MEDIAN
Classical pollutants, mg/L:						
BOD(5)	8	6	1.9 - 37,000	25	18 - 73	43
COD	25	7	11 - 110,000	330	0 - 99	59
TSS	13	9	<1.3 - 2,600	13	6 - 99	59
TOC	30	10	6.2 - 67,000	120	5 - 99	55
Total phosphorus	8	1	<0.07 - 14	1.5	0 - 57	5
Total phenols	5	5	<0.005 - 4.3	0.02	38 - 97	86
Oil and grease	7	2	2.2 - 82	8.4	5 - 92	26
Aluminum	8		0.02 - 9.2	0.13	0 - 81	30
Manganese	8		<0.005 - 0.61	0.03	14 - >90	40
Vanadium	8		0.006 - 0.18	0.03	0 - 65	25
Barium	8		<0.001 - 0.08	0.014	0 - 55	29
Iron	8		0.02 - 1.9	0.24	24 - 93	59
Sulfides	2		<0.005 - 0.01	0.008		50
Calcium	8		4.4 - 70	5.4	0 - 33	9
Magnesium	8		0.86 - 5.8	2.7	0 - 26	10
Sodium	7		51 - 260	170	0 - 8	6
Molybdenum	8		<0.01 - <0.2	<0.01		0
Cobalt	8		<0.006 - <0.04	<0.006	14 - 82	>33
Boron	8		0.009 - 1.1	0.48	0 - 50	4
Ammonia	6		0.21 - 19	1.25	5 - 15	10
Toxic pollutants, µg/L:						
Antimony	14	1	1.3 - 590	<25	0 - 33	19
Arsenic	14	1	<1 - 42	12	0 - >99	0
Beryllium	14		<0.04 - 5.4	<2		NM
Cadmium	14	3	<1.5 - <40	<2	76 - 95	86
Chromium	15	3	<4 - 260	<20	10 - 95	42
Copper	16	3	<4 - 360	<18	13 - >85	>64
Cyanide	11		<2 - 52	<5	>1 - >90	>63
Lead	15	2	<18 - 79	<22	2 - >72	5
Mercury	6		<0.01 - <1.1	<0.5		0
Nickel	15	3	BDL - <700	<36	10 - 68	39
Selenium	11		<1 - 50	<20	0 - 50	11
Silver	15	2	1.7 - <100	<5	12 - 36	24
Thallium	11		<15 - <50	<15		NM
Zinc	16	3	<1 - 6,000	69	5 - >99	64
Bis (2-ethylhexyl) phthalate	7	3	4.7 - 410	25	26 - 66	46
Butyl benzyl phthalate	2	1	BDL - 17	BDL	53 - 99	97
Di-n-butyl phthalate	7	2	BDL - 11	1.1	0 - 99*	76
Diethyl phthalate	3	1	1.2 - 9.5	0.85		5
Dimethyl phthalate	1			BDL		NM
Di-n-octyl phthalate		1		4		20
N-nitrosodiphenylamine	1			0.4		NM
N-nitrosodi-n-propylamine	1			BDL		NM

TABLE VII-13

CONTROL TECHNOLOGY SUMMARY FOR ACTIVATED CARBON ADSORPTION-GRANULAR FOR SEVERAL INDUSTRIAL GROUPS [217]

(Continued)

	DATA POINTS		EFFLUENT CONCENTRATION		REMOVAL EFFICIENCY, %	
POLLUTANT	PILOT SCALE	FULL SCALE	RANGE	MEDIAN	RANGE	MEDIAN
2,4-Dichlorophenol	2		BDL - BDL	BDL		NM
2,4-Dimethylphenol	2		BDL - 0.9	0.7		NM
Pentachlorophenol	2	2	BDL - 49	6.5	59 - 99*	79
Phenol	7	2	BDL - 49	7	0 - 98*	50
p-Chloro-m-cresol	2		BDL - BDL	BDL		17*
Benzene	3	1	BDL - 210	5	64 - 90	77
Chlorobenzene	1			BDL		98*
1,2-Dichlorobenzene	3		BDL - 5.4	BDL		99*
Ethylbenzene	7		BDL - 1.3	BDL		50*
Toluene	8	3	BDL - 630	1.6	23 - 99	75
1,2,4-Trichlorobenzene	1	1	ND - 94	47		>99
Anthracene	5		BDL - 0.4	0.1	50 - 97*	80
Benzo(a)pyrene	2		BDL - 0.8	0.41		95
Benzo(k)fluoranthene	1			BDL		90
Fluoranthene	2		BDL - BDL	BDL	88*- 95	92
Fluorene	1			BDL		NM
Napthalene		1		78		51
Phenanthrene	2		BDL - BDL	BDL	97*- 99*	98*
Pyrene	2		BDL - BDL	BDL	95*- 98	97*
Chloroethane	12		ND - 240,000	2,300	0 - >99	>99
Chloroform	5	1	ND - 18	BDL	64*- >99	>99
1,1-Dichloroethane	10	1	ND - 45,000	ND	42 - >99	>99
1,2-Dichloroethane	13		ND - 760,000	90	21 - >99	>99
1,1-Dichloroethylene	1	1	ND - 1.4	0.7		>99
1,2-Trans-dichloroethylene	3	1	1.1 - 140	58	96 - 98	97
1,2-Dichloropropane	4		ND - BDL	ND	65*- >99	>99
Methylene chloride	9	2	1.8 - 940	19	0 - 99	70
Tetrachloroethylene	3		BDL - 32	BDL		68
1,1,1-Trichloroethane	2	1	ND - 1.9	ND	99 - >99	>99
1,1,2-Trichloroethane	3		ND - ND	ND	>99 - >99	>99
Trichloroethylene	3	1	BDL - 5	2.5	58 - 99	75
Trichlorofluoromethane	2		BDL - 69	35		NM
Vinyl chloride	3		1,100 - 9,600	8,600		52
Alpha - BHC	1			1.9		NM
4,4'-DDT	1			BDL		NM
Heptachlor	1			BDL		NM

Blanks indicate data not available.

BDL, below detection limit.

ND, not detected.

NM, not meaningful.

* Approximate value.

Field investigations have indicated that some Gulf Coast facilities have sand removal equipment that flushes the sand through the cyclone drain valves, and then the untreated sand is bled into the waste water and discharged overboard.

No sand problems have been indicated by the operators in the Cook Inlet area. Limited data indicate that California pipes most of the sand with produced fluids to shore where it is separated and sent to State approved disposal sites.

At least one system has been developed that will mechanically remove oil from produced sand. The sand washer systems consist of a bank of cyclone separators, a classifier vessel, followed by another cyclone. The water passes to an oil water separator, and the sand goes to the sand washer. After treatment, the sand is reported to have no trace of oil, and the highest oil concentration of the transferred water was less than 1ppm of the total volume discharged. [3]

DECK DRAINAGE

Where deck drainage and deck washings are treated in the Gulf Coast, the water is treated by gravity separation, or transferred to the production water treatment system and treated with production water. Platforms in California pipe and deck drainage and deck washings along with produced fluids to shore for treatment. In Cook Inlet, these wastes are being treated on the platform.

Field investigations conducted on platforms at Cook Inlet indicate that the most efficient system for treatment of deck drainage waste water in this area is gas flotation. Limited data indicate an average effluent of 25 mg/l can be obtained from this system. The field investigations found that deck drainage systems operate much better when crankcase oil is collected separately and when detergents are not used in washing the rigs. The practice of allowing inverted emulsion muds to get into the deck drain system, during drilling or workovers, also seemed to adversely effect treatment. [3]

BPT Technology

BPCT for deck drainage is based on control practices used within the oil producing industry and include the following:

1. Installation of oil separator tanks for collection of deck washings.

2. Minimizing of dumping of lubricating oils and oily wastes from leaks, drips and minor spillages to deck drainage collection systems.

3. Segregation of deck washings from drilling and workover operations.

4. O&M practices to remove all of the wastes possible prior to deck washings.

BPCT end-of-pipe treatment technology for deck drainage consists of treating this water with waste waters associated with oil and gas production. The combined systems may include pretreatment (solids removal and gravity separation) and further oil removal (chemical feed, surge tanks, gas flotation). The system should be used only to treat polluted waters. All storm water and deck washings from platform members containing no oily waste should be segregated as it increases the hydraulic loading on the treatment unit. [3]

SANITARY WASTES

There are two alternatives to handling of sanitary wastes from offshore facilities. The wastes can be treated at the offshore location or they may be retained and transported to shore facilities for treatment. Offshore facilities usually treat waste at the source. The treatment systems presently in use may be categorized as physical/chemical and biological.

Physical/chemical treatment may consist of evaporation-incineration, maceration-chlorination, and chemical addition. With the exception of maceration-chlorination, these types of units are often used to treat wastes on facilities with small complements of men or which are intermittently manned. The incineration units may be either gas fired or electric. The electric units have been difficult to maintain because of salt water corrosion and heating coil failure. The gas units are not subject to these problems but create a potential source of ignition which could result in a safety hazard at some locations. Some facilities have chemical toilets which require hauling of waste and create odor and maintenance problems. Macerator-chlorinators have not been used offshore but would be applicable to provide minimal treatment for small and intermittently manned facilities. At this time, there does not appear to be a totally satisfactory system for small operations.

The most biological system applied to offshore operations is aerobic digestion or extended aeration processes. These systems usually include: a comminutor which grinds the solids into fine particles; an aeration tank with air diffusers; a gravity clarifier return sludge system; and a tank. These biological waste treatment systems have proven to be technically and economically feasible means of waste treatment at offshore facilities which have more than ten occupants and are continuously manned. [3]

BPT Technology

BPCT for sanitary wastes from offshore manned facilities with 10 or more people is based on end-of-pipe technology consisting of biological waste treatment systems (extended aeration). The system may include a comminutor, aeration tank, gravity clarifier, return sludge system, and disinfection contact chamber or other equivalent system. Studies of treatability, operational performance, and flow fluctuations are required prior to application of a specific treatment system to an individual facility. [3]

DOMESTIC WASTES

Domestic wastes result from laundries, galleys, showers, etc. Since these wastes do not contain fecal coliform, which must be chlorinated, they must only be ground up so as not to cause floating solids on discharge. Traceration by a comminutor should be sufficient treatment.

Since these wastes contain no fecal coliform, chlorination is unnecessary. Treatment, such as the use of macerators, is required to guarantee that this discharge will not result in any floating solids. [3]

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VIII. COST, ENERGY, AND NON-WATER QUALITY ASPECTS

INTRODUCTION

This section presents the costs, energy requirements, pollution control and non-water quality aspects of the NSPS, BAT and BCT technologies discussed in Section VII. An analysis of these issues was conducted pursuant to Sections 304(b) and (c) of the Clean Water Act. Table VIII-1 summarizes the treatment options costed for each waste stream type. It is important to note that the technology costs contained herein represent the additional investment required beyond those costs associated with BPT technologies. In other words, the cost presented in this section are incremental costs and are related only to the specific control technology options which may be necessary for compliance with the recommended BAT or NSPS effluent limitations. This section also presents the non-water quality aspects of implementing the candidate BAT and NSPS technologies. These aspects include energy requirements, solid waste generation and disposal, air pollution and consumptive water loss.

COST METHODOLOGY

A critical factor that must be considered in the adoption of any effluent limitation guideline is the potential economic impact of such a regulation on the industry being regulated. In order to address this economic impact, the cost of the control technologies associated with the proposed effluent limitation guideline must be evaluated. Presented below is a discussion of the methodology used to develop cost data for control technologies applicable to the offshore oil and gas industry. These costs

TABLE VIII-1
OFFSHORE OIL AND GAS INDUSTRY
TREATMENT TECHNOLOGY OPTIONS COSTED

WASTE STREAM	TREATMENT TECHNOLOGY	UNIT PROCESSES USED							
		FILTRATION	PIPE TO SHORE	REINJECTION	PUMP TO DISCHARGE	CUTTINGS WASHER	HAUL TO SHORE	LAND DISPOSAL	MINERAL/ DIESEL
Drilling Fluids	o Land Disposal	-	-	-	-	-	X	X	-
	o Product Subst.	-	-	-	-	-	-	-	X
Drill Cuttings	o Land Disposal	-	-	-	-	-	X	X	-
	o Wash and Discharge	-	-	-	-	X	-	-	-
	o Product Subst.	-	-	-	-	-	-	-	X
Produced Water	o Reinjection New Wells Offshore	X	-	X	-	-	-	-	-
	o Reinjection in New and Existing Wells Offshore	X	-	X	-	-	-	-	-
	o Discharge Offshore	X	-	-	-	-	-	-	-
	o Discharge 1000' Offs. from Onshore	X	X	-	X	-	-	-	-
	o Discharge 3 Mi. Offs. from Onshore	X	X	-	X	-	-	-	-
	o Reinjection Onshore	X	X	X	-	-	-	-	-
Produced Sand		-	-	-	-	-	-	-	-
Deck Drainage		-	-	-	-	-	-	-	-
Sanitary Wastes		-	-	-	-	-	-	-	-
Domestic Wastes		-	-	-	-	-	-	-	-
Well Treatment Fluids		-	-	-	-	-	-	-	-

NOTE:
X INDICATES PROCESS COSTED.
- INDICATES PROCESS NOT COSTED

were then used to assess the economic impact of the proposed regulatory options on the industry in "Economic Impact Analysis of Proposed Effluent Limitations and Standards for the Offshore Oil and Gas Industry," EPA, 1985.

PRODUCED WATER

Oil and gas well production, in addition to the product, includes quantities of water containing various contaminants. These waters must be separated from the product and treated so that they may be disposed of in an environmentally acceptable manner.

Model Platform Approach

Since it was not practical to evaluate each individual platform to determine treatment costs, an alternative analytical approach was needed. In response to this need, 32 model platforms were developed to represent the platform population in the offshore oil and gas industry, including both existing and new sources [218]. For the purposes of this study, various model platform sizes, based on produced water discharge rates, were selected to represent the current and future industry profile. Table VIII-2 lists the model platform sizes used and the geographic location of each. These model platform sizes were judged to encompass the normal range of production volumes and produced water discharge volumes expected to occur at facilities in the Gulf of Mexico, the East Coast, the West Coast and various locations in Alaska. The maximum flow of produced water that could be expected at any time was used to size and cost the treatment equipment. The average flow of produced water over the life of the platform was used to estimate operating costs. In the discussions that follow, all control technology options were evaluated on the

TABLE VIII-2

OFFSHORE OIL AND GAS EXTRACTION INDUSTRY

PRODUCED WATER GENERATION

MODEL PLATFORM PRODUCED WATER MAX AND AVG FLOWS [219]

	LOCATION	NAME AND WELLS	PRODUCED WATER FLOW (BWPD)	
			MAX	AVG
OIL	Gulf of Mexico	Gulf 4	2000	1000
		Gulf 2X5	5000	2500
		Gulf 12	5000	2500
		Gulf 24	9000	4500
		Gulf 40	16000	8000
		Gulf 58	25000	12500
	Pacific Coast	Pacific 16	7400	3700
		Pacific 40	8700	9350
		Pacific 34	35000	17500
	Atlantic Coast	Atlantic 24	20000	10000
	Alaska- Cook Inlet	Cook Inlet 24	30000	15000
		Gravel Isl. 48	70000	35000
		Bering Pl. 48	80000	40000
	Beaufort Sea	Beaufort Pl.48	100000	50000
GAS	Gulf of Mexico	Gulf 4	1614	328
		Gulf 2X5	4037	433
		Gulf 12	4037	433
		Gulf 24	1211	217
	Pacific Coast	Pacific 16	5744	551
	Atlantic Coast	Atlantic 24	3074	2376
	Alaska	Cook Inlet 12	18432	1614

BWPD: Barrels water per day.

basis of these model sizes. The costs were developed for these model platforms on two bases:

(1) Model production platforms which are presently in place (existing sources). These platforms would be subject to BAT and BCT regulations, and

(2) Model platforms which are new sources and subject to New Source Performance Standards (NSPS).

Cost Development Factors

In order to develop cost estimates for the selected control technologies, certain fundamental factors were developed with respect to capital and operation/maintenance costs. These cost factors, which are independent of the specific technology under consideration, are based upon the following assumptions:

Capital Costs - Cost of Equipment

The costs of the equipment required for treatment and disposal were based on a report which presented engineering designs for various treatment technologies [219]. All equipment sizing was based on the maximum quantities of produced water as shown in Table VIII-2. The prices were obtained using material quantities and cost data obtained from equipment manufacturers, as well as from reference [219]. The unit prices were obtained from the 1981 Means Construction Cost Data Manual adjusted to 1982. The costs for well reinjection pumps and drivers were derived from equipment manufacturers quotes [220]. For equipment installation costs on offshore platforms, multipliers of 3.5 were used for skid-mounted equipment and 4.0 for equipment that has to be assembled on the platform. These multipliers were obtained from reference [9]. The following assumptions were used in the sizing of the unit processes:

- Filters are granular media, pressure type, designed to remove suspended solids and oil and grease from the produced water. Each system includes a spare filter unit for use during backwashing operations. Filtration rates vary from 1.5 gpm/sq.ft. to 6.0 gpm/sq.ft. depending on the flow of water to be filtered and filter manufacturers' recommendations.

- Disposal wells and pumps are rated at a maximum reinjection rate of 6,000 barrels of produced water per day (BWPD), each [20]. One spare well and one spare injection pump, with driver, are required at each onshore or offshore treatment facility. Therefore, a minimum of two wells and two pumps are provided at each model facility.

- All equipment is selected and sized for outdoor duty.

- Capital cost calculations for offshore electrical power eneration equipment are based on the total increase in generated power required for operation of the wastewater treatment and disposal facilities above a spare 25 horsepower that is presently available on the facility. Onshore power for land-based treatment is purchased from a local utility at a cost of $0.035/kilowatt-hr.

- The volumes of sludge to be handled were developed on conservative assumptions derived from contractor experience in the design, construction and operation of similar types of wastewater treatment processes.

- Filter backwash volumes are estimated as 3 percent of the total volume of water filtered.
- Solids in filter backwash water are at a concentration of 5,000 mg/l which would thicken to 20,000 mg/l in the backwash tank prior to dewatering.
- The filtered and backwashed solids are dewatered in a centrifuge, to 25 percent solids by weight.
- The water removed from the backwash solids is returned to the head of the treatment train.
- The dewatered backwash solids are stored on the platform in containers and periodically shipped to land by supply boat for disposal.

Three of the treatment and disposal options include the treatment of the produced water on shore. The cost estimates for these scenarios are based on the following assumptions:

- For new source oil facilities, oil-water separation occurs on shore; no separate pipe is used to transport the produced water to shore. This is present practice in various locations. However, if a third party pipeline (common carrier) is to be used for transport of the oil to shore, the pipeline company may require that oil-water separation take place on the platform to minimize the volume of water that is carried. In that event, a separate pipeline and transfer pumps for the produced water would be necessary and would be an added capital and annual expense [222]. For existing platforms all water separation was assumed to take place at the platform.

- For gas facilities, a separate produced water pipeline is included for both new and existing sources.
- It was assumed that the on-shore treatment facilities would be located one quarter mile inland at an elevation of 25 feet above sea level. At the higher model flow rates, and at a discharge distance of 1000 feet offshore, the hydraulic head would be sufficient so that disposal pumping is not required. For disposal three miles or more offshore, pumping would be required. For the lower model flow rates, pumping is required at all distances.
- Onshore and offshore reinjection wells are 3500 feet deep [223].
- The costs of complying with underground reinjection regulatory requirements are not included (i.e., UIC requirements under the Safe Drinking Water Act).
- Treatment equipment installation costs for onshore facilities do not include the 3.5 or 4.0 installation multiplier factors used for offshore installation. Instead, a standard onshore installation factor of 30% of equipment caital cost is used.

The base location is for facilities in the Gulf of Mexico with a capital cost multiplier of 1 used to determine installed costs. For offshore facilities in other areas the following cost multipliers were used.

Location	Capital Cost Multiplier for Installation[218]	Applicable to
Atlantic Coast	1.6	Equipment and wells
California Coast	1.6	Equipment and wells
Alaska		
Norton Basin	3.5	Equipment and wells
Beaufort Sea	3.5	Equipment and wells
Bristol Bay	3.5	Equipment and wells
Gulf of Alaska	3.5	Equipment and wells
Cook Inlet/Shelikof Strait	2.0	Equipment and wells
Cook Inlet/Shelikof Strait	2.5	Wells

Well Costs. The costs of offshore wells drilled specifically for the purpose of reinjection of produced water and the costs of reworked dry wells were obtained from a report prepared by Walk, Haydel and Associates, Inc., titled "Potential Impact of Proposed EPA BAT/NSPS Standards for Produced Water Discharges From Offshore Oil and Gas Extraction Industry" [223]. The costs for onshore reinjection wells were derived from a report titled "1982 Association Survey on Drilling Costs " prepared by the Statistics Department of the American Petroleum Institute [224]. These well costs vary greatly depending upon the demand for wells by industry at a given time and the well location. Table VIII-3 shows that the cost per foot of onshore wells can vary by as much as 250 percent. Although equipment costs increased between 1981 and 1982 [225] the cost of onshore wells decreased by as much as 47 percent during that same period.

Platform Costs. The additional areas required on offshore platforms to accommodate the treatment facilities were calculated using three assumptions:

- The maximum deck area that could be added to an existing platform is 1000 square feet.
- If more than 1000 square feet were required at an existing platform, an auxiliary platform would be required which is assumed to be installed in 150 feet of water.
- For new platforms, the required area and the required reinjection well slots would be included in the initial design.

The costs of auxiliary platforms were derived from the Brown and Root report [9]. The costs to construct additional space (cantilevered platform) on an existing platform are taken at an industry estimate of $220 per square foot. The cost of additional area on a new platform is $350 per square foot. Costs of additional well slots were estimated to be $148,000 per slot [227]. The costs of auxiliary platforms were estimated using the following formula, derived from [219] data:

Cost = ($1,406,000 + [square feet required - 1000] x $78) x ENR-CCI* (3825/2212). (*Engineering News Record - Construction

TABLE VIII-3

OFFSHORE OIL AND GAS INDUSTRY

TREATMENT OF PRODUCED WATER

DERIVATION OF ONSHORE REINJECTION WELL COSTS

GEOGR. LOCATION	AVERAGE DEPTH (FT)	AVERAGE COST ($1000)	AVERAGE COST/FT ($)	COST/ 3500 FT ($1000)	NUMBER OF WELLS	WEIGHTED COST ($1000)
COL. 1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7
Texas RR Comm.						
Dist. 2	3251	105	32	113	64	7235
Dist. 3	3281	211	64	225	96	21608
Dist 4	3087	162	52	184	76	13959
Louisiana (South)	3038	252	83	290	32	9272
Alabama	2980	214	72	251	50	12544
					318	64617

Weighted Cost Per Well: Sum Col. 7/Sum Col. 6 = $203,199

Say: $203,200

NOTES:

1. Data in Columns 1, 2, 3 and 6 from 1982 Association Survey on Drilling Costs, Statistics Dept., American Petroleum Institute, November 1983. [224]. Drilling costs are for the year 1982.

2. Costs in Column 3 include all costs associated with drilling wels including mobilization, engineering, contingencies, bonding, etc. (Ref. p. 63 in Report cited in Note 1).

3. Assumption is that costs are linear for depths to 3500 ft.

Cost Index - 3825 = average ENR-CCI for 1982, 2212 = average ENR-CCI for 1975.)

For BAT, i.e., platforms that are presently producing, it is assumed that either (1) the well slots required for reinjection are available by using exhausted or dry wells that could be reworked to serve as reinjection wells or (2) a combination of exhausted production wells, dry wells and new reinjection wells would be used. The additional platform space required is dedicated to wastewater treatment equipment.

For new sources, any additional deck area and well slots that would be required for reinjection purposes are included in the initial design. It was assumed that (1) fifteen percent of the total number of well slots on the platform are available for use as reinjection wells, and (2) the same rate of dry holes would be encountered at new platforms as were encountered at existing platforms and are available for injection wells. The costs of additonal deck area and well slots were not escalated by using the location multiplier because these items do not affect the cost of placing a facility in a particular geographical location.

Table VIII-4 shows the availability of dry holes for reinjection based upon the above assumptions. However, in estimating the costs for reinjection by new sources, the overriding assumption was that all well slots, both production and reinjection, would be included in the initial platform design since it would not be known if enough dry holes would be available until the development program nears completion.

Table VIII-5 presents the cost effects of locating onshore treatment facilities further inland or transporting the produced water

TABLE VIII-4
OFFSHORE OIL AND GAS EXTRACTION INDUSTRY - NSPS
PRODUCED WATER TREATMENT - ON PLATFORM FILTRATION AND REINJECTION DRY WELL AVAILABILITY AND COSTS FOR NEW WELLS AND DRY WELL REWORKING

MODEL PLATFORM	WELLS REQ'D*	USABLE DRY HOLES	NEW WELLS REQUIRED	COSTS FOR DRY WELLS REWORK	COSTS FOR NEW WELLS
Oil					
Gulf 4	2	1	1	390	725
Gulf 2X6	2	4	0	780	0
Gulf 12	2	4	0	780	0
Gulf 24	3	7	0	1170	0
Gulf 40	4	12	0	1560	0
Gulf 58	6	19	0	2340	0
Pacific 16	3	1	2	390	1450
Pacific 40	4	1	3	390	2175
Pacific 34	7	1	6	390	4350
Atlantic 24	5	3	2	1170	1450
Cook Inlet 24	6	2	4	780	2900
Gravel Isl. 48	13	3	10	1170	7250
Bering Plat.48	15	3	12	1170	8700
Beaufort Pl.48	18	3	15	1170	10875
Gas					
Gulf 4	2	1	1	390	725
Gulf 2X6	2	4	0	780	0
Gulf 12	2	4	0	780	0
Gulf 24	2	7	0	780	0
Pacific 16	2	1	1	390	725
Atlantic 24	2	3	0	780	0
Cook Inlet 12	4	1	3	390	2175

NOTES:

1. Costs are in $1000 - 1982

2. A new well costs $725,000. A reworked well costs $390,000. Not included in these figures is a multiplier of 1.10 (engineering) x 1.15 (contingencies) x 1.04 (bonding and insurance) = 1.316, applicable to both new well and reworked well costs.

3.* Includes one spare injection well per platform.

TABLE VIII-5
OFFSHORE OIL AND GAS INDUSTRY
PRODUCED WATER TREATMENT
INCREMENTAL COSTS OF EXTENDING PRODUCED WATER PIPELINES EITHER FURTHER OFFSHORE OR FURTHER INLAND (ONSHORE)
(All costs in 1982 $) [219]

MODEL PLATFORM	FLOW (BWPD)	DIA. (IN)	ADD'L CAP. COST/MILE ($1000)		ADD'L MAINT COST/MILE ($1000)		ADD'L ANNUAL COST/ MILE ($)	TOT. ANN. ADD'L COST/ MILE ($1000)	
			OFF.	ON.	OFF.	ON.		OFF.	ON.
Oil									
Gulf 4	2000	4	200	90	6.0	2.7	20	6.0	2.7
Gulf 2X5	5000	4	200	90	6.0	2.7	112	6.1	2.8
Gulf 12	5000	4	200	90	6.0	2.7	112	6.1	2.8
Gulf 24	9000	5	250	123	7.5	3.7	180	7.7	3.9
Gulf 40	16000	8	400	228	12.0	6.8	99	12.1	6.9
Gulf 58	25000	10	500	309	15.0	9.3	116	15.1	9.4
Pacific 16	7400	4	200	90	6.0	2.7	178	6.2	2.9
Pacific 40	8700	5	250	123	7.5	3.7	180	7.7	3.9
Pacific 34	35000	12	600	396	18.0	11.9	121	18.1	12.0
Atlantic 24	20000	8	400	228	12.0	6.8	185	12.2	7.0
Cook Inlet 24	30000	10	500	309	15.0	9.3	197	15.2	9.5
Gravel Island 48	70000	18	900	608	27.0	18.2	162	27.2	18.4
Bering Platform	80000	18	900	608	27.0	18.2	246	27.2	18.5
Beaufort Plat 48	100000	20	1000	673	30.0	20.2	269	30.3	20.5
Gas									
Gulf 4	1614	4	200	90	6.0	2.7	16	6.0	2.7
Gulf 2X5	4037	4	200	90	6.0	2.7	65	6.1	2.8
Gulf 12	4037	4	200	90	6.0	2.7	65	6.1	2.8
Gulf 24	1211	4	200	90	6.0	2.7	20	6.0	2.7
Pacific 16	5744	4	200	90	6.0	2.7	155	6.2	2.9
Atlantic 24	3074	4	200	90	6.0	2.7	52	6.1	2.8
Cook Inlet 12	18432	8	400	228	12.0	6.8	139	12.1	7.0

to shore from further offshore. These costs were prepared without the use of detailed plans and specifications and thus have an accuracy of approximately + or - 30 percent.

To arrive at total capital investment, a factor of 10 percent for engineering, 15 percent for contingencies and 4 percent for the costs of bonding and insurance were added to the base facilities costs (multiplier 1.1 x 1.15 x 1.04 = 1.316).

The costs for onshore treatment of produced water from existing offshore facilities includes the cost of piping and pumping of produced water to shore in a separate pipeline since many existing sources have BPT facilities and water separation at the platform.

Annual Operating and Maintenance Costs

Annual operating and maintenance costs were estimated based on average flows as shown on Table VIII-2.

The following operating and maintenance cost assumptions were used:

- Maintenance

  Maintenance is three percent of the total capital cost. Where dry wells are converted to reinjection wells, a cost equal to 3 percent of the cost of a new well was used since 3 percent of the reworking costs alone would not adequately reflect the total cost of reinjection well maintenance.

- Operating Personnel

  A salary of $30.00/hr per operator was assumed, which includes fringe benefits, insurance, etc.

- Electricity

  $0.035 per kilowatt-hr.

- Chemicals

  Prices were obtained from the Chemical Marketing Reporter.

- Other Power Costs

  Gas turbines are used for injection of produced water. Natural gas at the platform is the source of fuel. A bulk commercial rate for natural gas of $5 per 1000 cubic feet was used to determine the operating costs [231].

- Solids Disposal

  The cost of land disposal of sludge and solid is estimated to be $11.00 per barrel [228].

Cost of Treatment Options for Produced Water

Seven technologies for the treatment and/or disposal of produced water were studied [225]. These technologies are as follows:

- Biological treatment
- Chemical precipitation
- Filtration
- Activated Carbon Adsorption
- Air Stripping
- Breakpoint Chlorination
- Reinjection

As discussed in Section VII, only reinjection and filtration were retained as technologically feasible alternatives to implement on a national basis for this industry segment.

In addition to reinjection in wells, filtration and discharge to surrounding waters at the platform was costed as a disposal alternative. Where onshore treatment of the produced water was considered, the costs of disposal to surface waters at distances of 1000 feet and three miles offshore were estimated. Add-on costs as shown in Table VIII-5 were also considered where facilities may be located further inland and for production facilities that are further than three miles offshore.

For all treatment technologies studied it was assumed that a level of treatment at least equal to BPT was in place for existing sources and would be installed as a minimum for new sources since it is presently a requirement of the regulations. Therefore, the costs developed for the candidate technologies are incremental to BPT costs. The following six options were evaluated:

Option No.	Technologies
1	For new sources, produced water is filtered at the platform and disposed in new reinjection wells drilled for that purpose. This option was not applied to existing sources (BAT) since a combination of new, exhausted, and dry wells could be used for reinjection at existing facilities.
2	For existing sources, produced water is filtered at the platform and reinjected in reworked dry or exhausted production wells and in any additional new wells required to accommodate the necessary reinjection capacity.
3	Produced water is filtered at the platform and disposed by discharge to surface waters at the platform.
4	Produced water is filtered at shore and disposed to surface waters 1000 feet offshore.
5	Produced water is filtered at shore and disposed to surface waters 3 miles offshore.
6	Produced water is filtered at shore and disposed by reinjection in wells located at shore.

The capital and annual operating and maintenance costs were estimated for each of the options for both existing and new sources. These costs are summarized in tables VIII-6 and VIII-7, respectively.

TABLE VIII-6
OFFSHORE OIL AND GAS EXTRACTION INDUSTRY
PRODUCED WATER TREATMENT
SUMMARY OF CAPITAL AND ANNUAL O/M COSTS FOR EXISTING SOURCES
($1000-1982)

MODEL PLATFORM	O	P	T	I	O	N
	1	2	3	4	5	6
OIL						
Gulf 4	-	3600	1700	1500	2300	1800
	-	(164)	(93)	(90)	(115)	(107)
Gulf 2X5	-	5700	4300	1600	2500	2000
	-	(257)	(174)	(107)	(134)	(138)
Gulf 12	-	5700	4300	1600	2500	2000
	-	(257)	(174)	(107)	(134)	(138)
Gulf 24	-	7300	5200	2000	3000	2600
	-	(344)	(213)	(128)	(161)	(186)
Gulf 40	-	8600	5600	3100	4700	3900
	-	(447)	(236)	(184)	(236)	(276)
Gulf 58	-	10600	6000	3700	5800	5100
	-	(591)	(267)	(230)	(294)	(377)
Pacific 16	-	10300	5700	2800	4200	3700
	-	(456)	(262)	(189)	(234)	(247)
Pacific 40	-	14800	7700	5100	7800	5600
	-	(696)	(343)	(295)	(393)	(388)
Pacific 34	-	21800	9100	6900	10900	9700
	-	(1089)	(446)	(413)	(538)	(653)
Atlantic 24	-	15300	8000	5000	7600	6800
	-	(663)	(294)	(230)	313	(370)
Cook Inlet 24	-	26100	10200	7500	11700	1100
	-	(1069)	(367)	(323)	(451)	(559)
Gravel Isl. 48	-	70600	20800	22000	35200	33100
	-	(3052)	(1033)	(1143)	(1541)	(1780)
Bering Plat.48	-	72600	22400	22300	35500	35500
	-	(3204)	(1098)	(1181)	(1580)	(1922)
Beaufort Pl.48	-	91800	32600	26600	41300	41100
	-	(3964)	(1439)	(1362)	(1805)	(2231)
GAS						
Gulf 4	-	3400	1600	1300	2300	900
	-	(145)	(86)	(86)	(111)	(70)
Gulf 2X5	-	5600	4200	1600	2400	1000
	-	(213)	(164)	(96)	(111)	(73)
Gulf 12	-	5600	4200	1600	2400	1000
	-	(213)	(164)	(96)	(111)	(73)
Gulf 24	-	2900	1500	1300	2300	900
	-	(128)	(84)	(77)	(109)	(69)
Pacific 16	-	8200	5200	2700	4000	1700
	-	(295)	(198)	(137)	(165)	(99)
Atlantic 24	-	7300	5100	2400	3800	1500
	-	(298)	(197)	(124)	(166)	(115)
Cook Inlet 12	-	18700	9300	6400	9700	4400
	-	(623)	(317)	(233)	(333)	(187)

NOTE: Cost format presented as follows, e.g., 1000 - Capital
(700) - Annual

TABLE VIII-7
OFFSHORE OIL AND GAS EXTRACTION INDUSTRY
PRODUCED WATER TREATMENT
SUMMARY OF CAPITAL AND ANNUAL O/M COSTS FOR NEW SOURCES
($1000-1982)

MODEL PLATFORM	O 1	P 2	T 3	I 4	O 5	N 6
OIL						
Gulf 4	4400	4000	1800	500	1300	900
	(197)	(185)	(95)	(59)	(84)	(91)
Gulf 2X5	5100	4300	2500	700	1500	1100
	(261)	(237)	(123)	(77)	(103)	(137)
Gulf 12	5100	4300	2500	700	1500	1100
	(261)	(237)	(123)	(77)	(103)	(137)
Gulf 24	7400	6100	3400	800	1800	1400
	(389)	(350)	(163)	(90)	(123)	(201)
Gulf 40	9300	7500	3900	1100	2800	2000
	(536)	(482)	(186)	(125)	(177)	(311)
Gulf 58	12500	9900	4300	1300	3400	2700
	(755)	(677)	(215)	(159)	(223)	(454)
Pacific 16	8900	7400	3900	1200	2600	2100
	(376)	(331)	(209)	(102)	(146)	(237)
Pacific 40	14400	13700	6000	1800	4300	3300
	(648)	(627)	(292)	(154)	(234)	(423)
Pacific 34	22700	22000	7500	2300	6300	5100
	(1048)	(1027)	(397)	(212)	(337)	(728)
Atlantic 24	16600	14400	6300	1900	4600	3700
	(721)	(655)	(243)	(159)	(242)	(394)
Cook Inlet 24	27300	25400	8600	2700	6900	6300
	(1143)	(1086)	(319)	(213)	(341)	(594)
Gravel Isl. 48	75200	70600	20800	6900	20000	18000
	(3145)	(3007)	(1033)	(710)	(1106)	(1758)
Bering Plat.48	85900	81300	20900	7100	20300	20300
	(3545)	(3413)	(1054)	(749)	(1148)	(1960)
Beaufort Pl.48	110400	105800	31400	9700	24400	26100
	(4457)	(4319)	(1402)	(886)	(1330)	(2400)
GAS						
Gulf 4	4300	3900	1700	1000	1400	900
	(175)	(163)	(89)	(74)	(83)	(72)
Gulf 2X5	5000	4100	2400	1600	2400	1000
	(199)	(172)	(110)	(96)	(111)	(79)
Gulf 12	5000	4100	2400	1600	2400	1000
	(199)	(172)	(110)	(96)	(111)	(79)
Gulf 24	4200	3300	1700	1000	1400	900
	(169)	(142)	(89)	(75)	(81)	(69)
Pacific 16	7500	6800	3500	2700	4000	1700
	(272)	(251)	(146)	(133)	(161)	(104)
Atlantic 24	7200	5800	3300	2400	3500	1500
	(299)	(257)	(142)	(128)	(161)	(140)
Cook Inlet 12	19800	19000	7600	6400	9700	4400
	(657)	(633)	(266)	(237)	(337)	(207)

NOTE: Cost format presented as follows, e.g., 1000 - Capital
(700) - Annual

DRILLING FLUIDS AND CUTTINGS

Drilling fluids can be either oil or water based. Oil may be added to a water-based drilling fluid as a lubricity agent or when it is necessary to free a stuck drill bit or string. When a replacement drilling fluid is needed to meet the requirements of a change in the formation characteristics or when a well is completed, the used drilling fluid must be disposed. In addition, as the drilling operation takes place a portion of the drilling fluid may have to be purged to maintain the proper formula, density, etc.

The following assumptions were made in determining costs of drilling solids disposal:

- Based on data in the "1982 Association Survey on Drilling Costs," API, Independent Petroleum Association and Mid-Continent Oil and Gas Association, November 1983, 10,000-feet was used as an average well depth for the Gulf of Mexico. The drilling time for this well would be 35 days with 20 days of actual drilling [228]. The time required to drill from 8,000-feet to 10,000 feet was assumed to be 8 days.

- The amounts of drilling fluids and cuttings generated for a 10,000-foot well are as follows [228]:

Well Depth(ft)	Mud Used (bbls)	Cuttings Discarded (bbls)
0-150	-*	188
150-1,000	1,477	258
1,000-4,500	2,012	551
4,500-8,000	1,184	275
8,000-10,000	676	158
Subtotals	5,349	1,430
Total:	6,779 bbls	

*Assuming casing water jetted so no drilling fluids are used or generated.

Diesel and mineral oil may be used in the drilling operations. Various scenarios were developed when these oils are used and costs of disposing the generated solids were determined. The scenarios developed are as follows:

- Scenario 1.- Drilling muds are diesel oil-based for the entire 10,000 foot drilling depth (rarely done).

- Scenario 2.- Drilling muds are water-based, with diesel oil used as a lubricity agent down to the 8,000 foot level. Between 8,000 and 10,000 feet a diesel spot is added to the mud system to free a stuck drill bit or string.

- Scenario 3.- Drilling muds are water-based with no lubricity agent added. However, diesel oil is used as a spotting agent between 8,000 and 10,000 feet.

With the three scenarios stated, various degrees of treatment were considered:

- Removal of diesel oil from discharges (product substitution)
- Removal of all oils from discharges (land disposal)
- Removal of some oils and some solids from discharges (land disposal)
- Removal of all oil and solids from discharges (land disposal)

The unit costs used in estimating the treatment and disposal alternatives are based on the following:

- The increased cost of substituting mineral oil for diesel oil is $1.90 per gallon including storage and maintenance [230].

- The cost for washing cuttings over a 35-day period for drilling a single well, is estimated at $54,000. This includes daily rental charges for the cuttings washer and operating costs during actual days of drilling [228].

- The cost of a dedicated boat for transporting solids to land is $3000 per boat per actual day of drilling [228,229].

- The total cost of land disposal of solids is $11 per barrel [228].

Costs for Scenario 1

The cost of treating and handling the muds and cuttings in Scenario 1 to the point of removing all diesel oil from use and removing a portion of the substituted mineral oil and a portion of the solids from discharge is $509,000 per well. The operations involved, and their respective costs, are as follows:

Substitute mineral oil for diesel oil	$276,000
Wash oil from drill cuttings	54,000
Discharge washed cuttings	0
Transport oil-based mud to shore for disposal	179,000
Total	$509,000

The total cost of removing all oils and all mud and cuttings discharges by transporting to shore for disposal is $195,000.

Costs for Scenario 2

The costs of treating the muds and cuttings in Scenario 2 to remove all diesel oil from use is $29,000 per well. The operations involved, and their respective costs, are as follows:

Substitute mineral oil for diesel oil (as lubricant spotting fluid)	$ 29,000
Discharge to surrounding waters	0
Total	$ 29,000

The total cost for removing all oils and all solids from the discharges by transporting to shore for disposal is $195,000.

Costs for Scenario 3

The costs of treating the muds and cuttings in Scenario 3 to remove all diesel from use by substituting mineral oil for diesel oil is $3300 per well. The operations involved, and their respective costs, are as follows:

Substitute mineral oil for diesel oil as a spotting fluid	$ 3,300
Discharge to surrounding waters	0
Total	$ 3,300

The total cost for removing all oils and solids from discharges by transporting to shore for disposal is $195,000.

DISPOSAL OF SOLIDS OTHER THAN DRILLING FLUIDS AND CUTTINGS

The volume of dewatered solids generated as a result of produced water pretreatment prior to reinjection is estimated at approximately 0.06 percent of the volume of produced water. They may be disposed of by deposition on the sea bed in the vicinity of the platform or transported to shore and disposed of in landfills. The cost of disposal on the sea bed is virtually nil. The cost of disposal on land is $11 per barrel plus the costs of platform storage containers and transportation to shore.

ENERGY REQUIREMENTS

Additional energy requirements of the candidate treatment technologies are due primarily to the filtration and pumping of produced water into reinjection wells for those new source facilities subject to the zero discharge standard. The energy requirements for the estimated 132 new source platforms that would be required to reinject produced water total approximately 170 million kilowatt-hours per year. This represents approximately 0.05 percent of the energy content of the produced hydrocarbons from these facilities. Therefore, the small incremental energy requirements for reinjection of produced water will not significantly affect the cost of production, nor will they significantly reduce energy supplies.

There are no measurable increases in energy requirements beyond BAT for those new sources that would be subject to improved performance of BPT technology for produced water.

Table VIII-8 illustrates the effect of reinjection on the power requirements. It compares the power requirements of filtration and surface water disposal and filtration with reinjection. The difference between the two is the power required for injection well disposal.

TABLE VIII-8

TOTAL ANNUAL POWER REQUIREMENTS

(THOUSANDS OF KILOWATT HOURS)

MODEL PLATFORM	FILTRATION AND REINJECTION (OPTION 2)	FILTRATION AND SURFACE WATER DISPOSAL (OPTION 3)
Gulf 4	330	74
Gulf 2X5	830	180
Gulf 12	830	180
Gulf 24	1390	230
Gulf 40	2310	260
Gulf 58	3520	300
Pacific 16	1200	240
Pacific 40	2740	340
Pacific 34	4840	350
Atlantic 24	2860	280
Cook Inlet 24	4180	320
Gravel Island 48	9500	500
Bering Platform 48	10830	540
Beaufort Platform 48	13470	620

AIR POLLUTION

When additional pumping is required, due to the application of a particular pollution control technology for produced water, additional air emissions will be created due to the use of fuel to power either electric generators or prime movers. However, the use of gas turbine engines is projected for the majority of sites offshore which should result in minimum emissions to the atmosphere when compared to the pollutant removals associated with the treatment technologies. If treatment facilities are located on-shore, power would be obtained from local electric power companies.

CONSUMPTIVE WATER LOSS

Since no water is added to any of the unit operations no consumptive water loss is expected as a result of the proposed regulations.

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IX. NEW SOURCE PERFORMANCE STANDARDS

The basis for new source performance standards (NSPS) under Section 306 of the Act is the best available demonstrated control technology. When new facilities are planned, the operators have the opportunity to incorporate in their designs the best and most efficient processes and waste treatment technologies. Therefore, Congress directed EPA to consider the best demonstrated process changes, in-plant controls, and end-of-process control and treatment technologies that reduce pollution to the maximum extent feasible.

The Agency has investigated several control and treatment options as a basis for NSPS to reduce the discharge of pollutants in waste streams generated by the offshore segment of this industry. These options and the rationale for selecting NSPS are presented in this section for the waste streams covered by the proposed regulation.

NEW SOURCE DEFINITION

The exploration, development, and production of oil and gas in offshore waters involves operations sometimes unique from normal industrial operations performed on land. While the provisions in the NPDES regulations that define new source (40 CFR 122.2) and establish criteria for a new source determination (40 CFR 122.29(b)) are applicable to this subcategory, two terms, "water area" and "significant site preparation work," are defined in this subcategory-specific new source definition in order to give the terms meanings relevant to offshore oil and gas operations. These special definitions are consistent with Section

122.29(b)(1) which provides that Sections 122.2 and 122.29(b) shall apply "except as otherwise provided in an applicable new source performance standard." See 49 FR 38048 (September 26, 1984).

Before discussing the two special definitions, a brief discussion follows on the scope of the term "new source" as applicable to all activities covered by the offshore subcategory. This includes mobile and/or fixed exploratory and development drilling operations as well as production operations. Coverage of all such offshore oil and gas operations is required by Section 306 of the Act.

Section 306(a)(2) defines a "new source" to mean "any source, the construction of which is commenced" after publication of the proposed NSPS if such standards are promulgated consistent with section 306. The Act defines "source" to mean any "facility ... from which there is or may be the discharge of pollutants" and "construction" to mean "any placement, assembly, or installation of facilities or equipment...at the premises where such equipment will be used." The term "source" clearly would include all drilling rigs and platforms as well as production platforms. The breadth of the term "construction," which encompasses the concept of "placement" of "equipment" at the "premises," would include the location and commencement of drilling or production operations at an offshore site to be "construction" of a new source. This is a critical distinction. Drilling rigs obviously are moved from site to site for several years. Production platforms are built on shore and transported to an offshore site. The appropriate reading of section 306(a)(5) would not make the date of building the rig or platform determinative of whether the rig or platform was a new source, but rather when the rig or platform was placed at the offshore site where the drilling and production activity and discharge would occur. Therefore, drilling operations that commence after the NSPS are effective, even if performed by an existing mobile rig, would be new sources, coming within the definition of "constructed" by "placement" of "equipment" at the "premises."

Similarly, a mobile drilling rig which carries the drilling equipment would be considered "placed" at the location it anchors for drilling, which would be the "premises." The Agency considers the drilling rig to be the "facility...from which there is or may be the discharge of pollutants" within the meaning of Section 306(a)(3). The same reasoning applies to development drilling rigs and structures and production structures, platforms or equipment. The critical determination of whether a source is a "new source" is the date of placement and commencement of operations, not the date the source originally was built.

The first special term that is defined in these proposed regulations is "water area" as used in the term "site" in Section 122.29(b). The term "site" is defined in Section 122.2 to include the "water area" where a facility is "physically located" or an activity is "conducted." For the purposes of determining the "site" of new source offshore oil and gas operations, the Agency is proposing to define "water area" to mean the specific geographical location where the exploration, development, or production activity is conducted, including the water column and ocean floor beneath such activities. Therefore, if a new platform is built at or moved from a different location, it will be considered a new source when placed at the new site where its oil and gas activities take place. Even if the facility is placed adjacent to an existing facility the new facility will still be considered a "new source," occupying a new "water area" and therefore a new site.

EPA considered defining "water area" as a larger body of water, such as a lease block area. This alternative was rejected because such an artificial distinction would allow the commencement of many additional oil and gas activities (not considered to be "new sources") in an area merely by virtue of the fact that an existing activity was currently operating in the lease block. This result is inconsistent with the definitions and purpose of Section 306 of the Act. Under Section 306 a "new source" means "any source" the construction of which begins after the Agency publishes a NSPS.

The second special term for which EPA is proposing a special definition is "significant site preparation work." As explained above, the date of "placement" of a rig or platform is determinative of when a source is considered to be "constructed." The date of "placement" (i.e., "construction") may be earlier under the provision of 40 CFR 122.29(b)(4) which defines construction as being commenced when "significant site preparation work" has been done at a site. The effect of the proposed definition for "significant site preparation work" is important in determining what individual sources would be considered to have "commenced construction" or commenced "placement" prior to the publication of the NSPS and therefore, would not be considered a new source. EPA is proposing to define this term to mean the processes of clearing and preparing an area of the ocean floor for purposes of constructing or placing a development or production facility on or over the site. Therefore, if clearing and preparation of an area for development or production had occurred at a site prior to the publication of the NSPS, then subsequent development and production activities at that site would not be considered a new source. The significance of this definition is that exploration activities at a site prior to the effective date of the NSPS are not considered significant site preparation work. Therefore, if only exploratory drilling had been performed at a site, subsequent development and production activities would not be "grandfathered in" as existing sources at the site but rather would be considered "new sources". The Agency does not consider exploratory activities to be "significant site preparation work" because such activities are not necessarily followed by development or production activities at a site. Even when exploratory drilling ultimately leads to drilling and production activities, the latter may not be commenced for months or years after the exploratory drilling is completed. The purpose of this provision is to allow a future source to be considered an existing source if "significant site preparation work," thereby evidencing an intent to establish full-scale operations at a site, had been performed prior to NSPS becoming effective. While a development or production platform would not be built unless an exploratory well had been drilled, exploration wells are drilled at vastly more sites and can precede development by months or years.

Another provision of Section 122.29 (b)(4) regarding when construction of a new source has commenced, provided that construction has commenced if the owner or operator has "entered into a binding contractual obligation for the purchase of facilities or equipment which are intended to be used in its operation within a reasonable time." The Agency is not proposing a special definition of this provision believing it should appropriately be a decision for the permit writer. However, the Agency carefully has considered this provision and is providing the following general guidance concerning the proper application of the provision for the special circumstances of offshore oil and gas activities.

A common practice in the industry is for oil companies to enter into long-term contracts with independent drilling companies. These contracts may require that the drilling company will provide its services for a specified number of wells over a period of months or years. The exact site for the exploratory drilling services may not be specified. The Agency believes such contracts would appropriately fall within the provision of Section 122.29(b)(4)(ii), thereby making the drilling activities under those contracts existing sources, not new sources. Such contracts generally do not or cannot specify the exact site for future exploratory drilling.

The situation generally is not the same for development drilling or production activities. Contracts for these activities usually specify the site where activities are to be conducted or facilities placed. Therefore, drilling activities under a contract that meets the conditions of Section 122.29(b)(4)(ii) for an exact site probably would not be considered a new source. However, a general contract for construction or use of a development or production platform with no indication of the location where it would be placed or used would not qualify to make a future selected site for its use an existing source. An opposite result would allow companies to move an existing platform or use old platforms at new sites in shallow water areas thereby avoiding the NSPS zero discharge requirement for produced water. Such a result would be contrary to the purpose of establishing NSPS.

An issue of continuing concern under the Clean Water Act has been whether NSPS must be applied after their proposal or only after their promulgation. Section 306(a)(1) of the Act provides that a "new source" is a source, the construction of which commences after proposal of NSPS if such NSPS are promulgated in accordance with Section 306. Section 306(b)(1)(B) requires promulgation within 120 days of proposal. EPA's implementing regulations for direct discharges provide that a new source means a source, the construction of which commenced either after proposal if the NSPS are promulgated within 120 days or after promulgation in all other cases (Section 122.2).

EPA does not intend that the NSPS for this subcategory shall be effective until they are promulgated unless they are promulgated within 120 days of proposal in which case the effective date would be the date of proposal. Therefore, no source will be considered a "new source" subject to NSPS until the Agency promulgates the NSPS. This decision is consistent with the Agency's definition of "new source" in 40 CFR 122.2 since for the reasons discussed below the Agency will not be able to promulgate NSPS within 120 days of proposal. While the Agency continues to believe the definition of new source in Section 122.2 is appropriate and consistent with the Act, the Third Circuit Court of Appeals has twice in NAMF v. EPA, 719 F.2d 624, 641 (3rd Cir. 1983) and Pennsylvania Department of Environmental Resources v. EPA, 618 F.2d 991 (3rd Cir. 1980), held that as a general matter EPA's new source standards shall be applied as of their date of proposal. However, the Court in those cases also recognized that there may be circumstances, such as cases where "substantial changes" may occur between proposal and promulgation that would justify an NSPS effective date as the date of promulgation. See NAMF v. EPA, 719 F2.d at 643 n.20. The Agency believes that these proposed regulations are such a case, as discussed below.

First, one of the issues is the definition of "new source." The Agency has solicited public comment on the proposed definition of new source. The Agency's final decision on the definition of new source for this subcategory will be critical to knowing what facilities must comply with the NSPS. Because the proposed definition of NSPS may change upon promulgation, individual dischargers would be unable to determine their status for an extended period of time. This would hinder operational planning during the period.

Second, the proposed standards may change on promulgation. After proposal and prior to promulgation, the Agency will be collecting substantial additional data on the proposed standards and will be reconsidering its decisions. In light of this fact and the substantial number of expected comments, it seems inappropriate to require compliance with the proposed NSPS.

Finally, one of the primary effects of a decision to apply NSPS at the date of proposal would be that the National Environmental Policy Act (NEPA) would apply to the action of issuing the permit for the new source. For new lease areas, the Department of Interior ("DOI") already is preparing environmental impact statements (EIS) that consider the proposed oil and gas operations in the lease areas. EPA has entered into a memorandum of understanding with DOI providing for EPA participation in the EIS process. Therefore, for new federal lease areas, the provisions of NEPA are being applied.

PRODUCED WATER

Control and Treatment Options Considered

EPA evaluated the following three control and treatment options for establishing NSPS for produced water.

Option 1 - Improved BPT Performance. Option 1 would base performance standards on the improved performance of BPT technology. A discharge standard of 59 mg/l (maximum) for oil and grease would result from this option. For the 833 projected new source platforms in the years 1985 thru 2000 [252], this level of technology would result in an annual reduction of 700,000 pounds of oil and grease beyond the allowable BPT discharge level. Reductions of priority pollutants beyond those achieved by existing BPT-type treatment technologies cannot be quantified for this option.

The Agency was unable to develop incremental cost estimates for imposing Option 1 on all new source platforms. This is because the elements of improved operation and maintenance of BPT treatment equipment are very site specific. However, the Agency does believe that, for any particular new source platform, such costs are minimal compared to the installed costs of the BPT equipment and the cost of operation and maintenance to achieve the BPT effluent limitations. Also, new source operators have the opportunity to design for and install the latest equipment as an integrated part of the platform superstructure; therefore they would not be subject to any retrofit expenditures that would be required by existing platforms to comply with improved BPT treatment technologies. Furthermore, the Offshore Operator's Committee report titled Potential Impact of Proposed EPA BAT/NSPS Standards for Produced Water Discharge From Offshore

Oil and Gas Extraction Industry (January 1984), projects that at least 75 percent of the existing offshore platforms in the Gulf of Mexico are already achieving the 59 mg/l oil and grease limitation with treatment technology designed to achieve compliance with the present BPT limitations.

Option 2 - Filtration. Option 2 would base performance standards on granular media filtration as an add-on technology to BPT. This level of technology would result in additional reductions of conventional pollutants beyond the BPT level of control. Effluent limitations of 20 mg/l monthly average and 30 mg/l daily maximum for both oil and grease and total suspended solids would result from this option. For the 833 projected new source platforms, this option would result in an annualized cost of $275.7 million in the year 2000 (1983 dollars). Investment costs for the 62 platforms expected to be installed in the year 2000 are estimated to be $185.4 million (1983 dollars). These compliance costs are incremental to BPT technology, i.e., they do not include the costs for BPT technology. [252]

This option would result in an annual reduction of 4.2 million pounds of conventional pollutants beyond the levels allowed under the BPT level of control. Significant reductions of total suspended solids levels are also achieved by granular media filtration. Reductions of priority pollutants cannot be quantified through the use of this option.

Option 3 - Zero Discharge. Option 3 would require zero discharge, based upon reinjection technology. This level of technology would result in no discharge of pollutants to surface waters.

For the projected 833 new platforms, this option would result in an annualized cost of $487.1 million in the year 2000 (1983 dollars). Investment costs for the 62 platforms expected to be installed in the year 2000 are estimated to be $442.0 million (1983 dollars). These compliance costs are incremental to BPT technology, which may be required ahead of the reinjection system required by this option.

This option would result in an annual reduction of 3.9 million pounds of priority pollutants beyond the discharge levels observed by existing platforms using BPT technology. This option would also result in an annual reduction of 7.0 million pounds of conventional pollutants (oil and grease) beyond the levels allowed under the BPT level of control. Significant reductions of total suspended solids levels are also achieved by this option.

Selected Option and Basis for Selection

The option which the Agency is proposing for NSPS is a combination of Options 1 and 3. Option 3, or zero discharge, would be required for all oil production facilities that are located in or discharge to shallow water areas, i.e., platforms in 20 meters of water or less in the Gulf of Mexico, the Atlantic Coast, and the Norton Basin; in 50 meters of water or less for the California Coast, Cook Inlet/Shelikof Strait, Bristol Bay, and Gulf of Alaska; and in 10 meters of water or less in the Beaufort Sea. The Agency has selected Option 1, improved BPT-treatment technology, which requires compliance with a 59 mg/l limitation for oil and grease (maximum), for all oil facilities that are not located in these shallow water areas, for all gas facilities regardless of location or water depth, and for all exploratory facilities.

This selected option would require an estimated 132 new oil production facilities to meet the zero discharge standard. The other 701 new facilities would be required to meet an oil and grease standard of 59 mg/l (maximum) based upon improved performance of BPT technology.

In selecting NSPS for produced water, the Agency considered the technical feasibility and industry compliance costs of imposing each of the above three NSPS options. In addition, EPA calculated aggregate industry compliance costs with various combinations of these options based upon platform type and location.

Because Option 3, which is based on reinjection, is the only treatment technology that EPA found to be both technologically feasible to implement and capable of achieving reductions of all pollutants, including priority pollutants, the Agency focused its evaluation on reinjection. The Agency recognized that, while reinjection is an available and demonstrated technology for controlling the discharge of pollutants in produced water from offshore oil and gas facilities, the Agency also had to consider the costs of implementing such a control option. The estimated total annualized cost for all 833 projected new facilities to implement reinjection of produced water is $487.1 million in the year 2000 (1983 dollars). In light of the statutory mandate to consider cost in establishing NSPS, EPA decided to reject the imposition of this option on all new facilities in the offshore subcategory because of its very high aggregate cost. This prompted the Agency to evaluate limiting the scope of a zero discharge requirement (i.e., reinjection) in order to reduce the total cost.

To analyze possible ways to reduce the total aggregate cost of Option 3, the Agency then developed costs for reinjection based upon the type of facility, i.e., oil platforms or gas platforms. Not imposing a zero discharge requirement on the estimated 537 new source gas platforms would reduce the annualized cost of NSPS Option 3 by $217.8 million in the year 2000 (1983 dollars). The Agency decided to exclude all gas platforms from coverage by Option 3 to reduce total aggregate costs.

To confirm this decision, EPA evaluated the characteristics of produced water from oil platforms versus gas platforms. The Agency determined that, while produced water from gas wells exhibits higher concentrations of the priority pollutants than produced water from oil wells (approximately fourfold higher), the typical flow of produced water from gas wells is significantly less (approximately 1/15) than that from oil wells. Thus, on a mass basis, discharges of priority pollutants from gas wells are approximately 25 percent of those from oil wells. The higher quantity of priority pollutants discharged from oil platforms compared to gas platforms supports the Agency's decision that deleting gas platforms from a zero discharge requirement to reduce aggregate annualized costs was appropriate. This reduced total annualized costs to $269.3 million (1983 dollars) while continuing to target attention on the discharges of greatest concern.

While total projected annualized costs were reduced, the Agency believed that $269.3 million was still too high and evaluated reducing costs further by limiting the zero discharge option to shallower waters where compliance costs would be less. Facilities in shallow waters generally have the alternative of onshore reinjection which is less costly than reinjection offshore.

The Agency has found that in shallower waters a high percentage of the existing production platforms pipe the produced water to shore for treatment rather than treating the produced waters on the platform. The Agency has also determined that the costs of drilling reinjection wells on land is less costly than drilling reinjection wells at the platform.

The Agency has selected variable depth limits for different offshore development areas which represent the shallower waters and which generally allow for the alternative of onshore reinjection by the facility.

Industry data for the Gulf of Mexico indicate that 82 percent of the projected new sources in state waters and 25 percent of the projected new sources in federal waters would pipe produced water to shore for treatment. The data also indicate that about 52 percent of all new sources in 15 meters or less of offshore waters would pipe produced water to shore. The Agency believes this same percentage of platforms in water depths of 20 meters or less could pipe to shore and reinject.

The 20 meter water depth was also selected for the Atlantic Coast. There is no historic trend for production platforms in this area. Therefore, the Gulf of Mexico statistics on the probable practice of onshore reinjection were assumed to be applicable for production facilities in the Atlantic Ocean.

In California, statistics indicate that 60 percent of the active production platforms located in water depths of 50 meters or less pipe produced water to shore for treatment; whereas only eight percent of the facilities in greater than 50 meters pipe the produced water to shore for treatment. Based on this data, reinjection of produced water was selected at a depth of 50 meters or less for the California Coast.

The Agency does not have historic data on production platforms for some parts of Alaska since no offshore production platforms have been constructed to date in the offshore subcategory. All of the 14 existing production platforms in Cook Inlet are classified in the coastal subcategory. The Agency believes that the Southern Alaskan bathymetry is somewhat similar to California's bathymetry and therefore, reinjection is proposed for platforms at water depths of 50 meters or less for Southern Alaska since platforms locating is these water depths may choose to pipe produced water to shore for treatment. The Southern Alaska region includes the Bristol Bay/Aleutian Island Chain, Cook Inlet and the Gulf of Alaska. The Agency realizes that some of these areas may not be amenable to piping or onshore reinjection because of seasonal ice formations, glaciers, or unsuitable terrain. However, the Agency believes that piping to shore in shallow waters will occur in areas that are suitable.

For other parts of Alaska, the Agency believes the platforms which locate in the Norton Basin in water depths of 20 meters or less and in the Beaufort Sea in 10 meters or less will have the option of piping produced water to shore for treatment. These more northern regions have harsher climates and thus a lesser probability of piping the produced water to shore for treatment.

The Agency developed a zero discharge option for platforms located in 20 meters of water or less in the Gulf of Mexico, the Atlantic Coast and the Norton Basin; for 50 meters of water or less for the California Coast and Southern Alaska including the Aleutian Island Chain; and for 10 meters of water or less in the Beaufort Sea.

EPA then calculated the total costs of this zero discharge option in shallower waters. In the Gulf of Mexico, the Agency projects that 124 new platforms will be built in 20 meters of water or less by the year 2000. The Agency estimates annualized costs of a zero discharge standard to be $50.0 million in the year 2000 (1983 dollars). For the California Coast, the Agency projects two new platforms that will be built in 50 meters or less of water and estimates the annualized cost to be $5.5 million (1983 dollars). While six platforms are projected to be built in the shallow waters of the Beaufort Sea, the Agency is not attributing incremental compliance costs to this regulation because existing Department of Interior and State of Alaska lease stipulations already require zero discharge. However, these costs are included in the Agency's baseline economic analysis for these proposed regulations. Similarly, no costs are attributed to Atlantic Coast operations because no facilities are projected to be built in 20 meters of water or less by the year 2000. Nonetheless, EPA realizes that development is possible in the Atlantic and has found that reinjection technology is feasible for meeting a zero discharge standard for platforms located in 20 meters of water or less for the Atlantic Coast.

The proposed regulatory option, developed from the variable depth considerations presented above, results in an annualized cost of $55.6 million in the year 2000 (1983 dollars). The annualized costs apply to 126 of the 132 new oil facilities expected to be built between 1986 and the year 2000 and which would be subject to this zero discharge requirement. The other six facilities are projected to be located in Alaskan waters and subject to reinjection, but the cost of reinjection is not attributed to this regulation, as described above. The Agency found these costs to be economically achievable. This cost represents the total annualized cost of NSPS because the Agency has selected improved BPT performance (i.e., 59 mg/l oil and grease maximum) for all facilities not required to meet the no discharge standard.

As explained above, the Agency assumes only minimal incremental costs for new sources to meet 59 mg/l oil and grease for produced water. The Agency selected Option 1 (improved BPT) over option 2 (filtration) because the aggregate annualized cost of $275.7 million (1983 dollars) to implement Option 2 is believed to be too high.

The proposed regulatory option would result in an estimated annual reduction of 700,000 pounds of priority pollutants beyond discharge levels observed at existing platforms using BPT technology. This option would also result in an annual reduction of 1.3 million pounds of conventional pollutants beyond the discharge levels allowed under the BPT level of control. No decline in energy production is projected to occur from this option.

Both reinjection and improved BPT technology represent the application of the best available demonstrated control technology to meet the proposed standards. The Agency has thoroughly considered the cost of achieving the proposed standards and concludes that the costs will not be a barrier to future entry into offshore oil and gas exploration, development or production operations. No adverse non-water quality environmental impacts or substantial increases in energy requirements will occur as a result of the proposed standards.

This proposed option would require produced water from all new exploration facilities regardless of location or water depth to comply with a 59 mg/l (maximum) oil and grease standard, based upon improved operation of BPT. Because of the relatively short duration of exploratory operations, only a small amount of produced water will be generated. In addition, each exploratory operation would require the drilling of an additional reinjection well if reinjection were required. The Agency concluded that the cost of a zero discharge requirement for exploratory operations was too high especially considering the small amount of produced water that would be generated.

EPA is proposing that development/production facilities that would have to implement zero discharge under this option would have up to 300 days from the commencement of well drilling operations to begin complying with the zero discharge standard. For this purpose, commencement of well drilling operations means the start of borehole drilling for the first development well at an offshore facility. During this 300-day period, any discharges of produced water would have to comply with a 59 mg/l (maximum) oil and grease standard, which is based upon improved performance of BPT technology. This 300-day period is being proposed in order to allow for the use of any dry (non-producing) wells that are drilled which are suitable for reinjection. If no dry wells become available and are ready for use as injection wells within this period, then compliance with the zero discharge standard would be achieved by drilling and equipping an injection well for use by the 301st day from the commencement of development drilling operations.

The 300-day allowance for discharge of produced water after commencement of development drilling, was selected based upon two factors. These factors are (1) the length of time required to drill a reinjection well and (2) the average percentage of development wells drilled that prove to be dry and would be used as reinjection wells. Fifteen percent has been established as the percentage of dry wells encountered and 35 days as the calendar time to drill a 10,000 foot injection well (20 days of actual drilling). Using 15% as the factor for dry wells encountered in development drilling, one in seven wells drilled will be a dry well. Seven wells times 35 days results in 245 days. Assuming a dry well is not encountered by the seventh well drilled, then 35 additional days are required to drill a reinjection well. Assuming that up to 20 more days are required to complete, connect, and start-up the reinjection well, a maximum of 300 calendar days from commencement of development drilling would lapse before an injection well were operating.

The Agency estimates that, typically, less than two percent by volume of the produced water generated over the life of a facility would be discharged during the initial 300-day period. The Agency estimates that the difference in cost between the use of a new injection well and use of a reworked dry well for reinjection is a minimum of $400,000 per facility. Because of these substantial costs, the Agency believes that it is reasonable to delay the requirement for meeting zero discharge by new offshore oil facilities for 300 days from the commencement of development drilling.

The reasonableness of the Agency's decision to require zero discharge in the shallow waters is confirmed by the Agency's analyses which show that it would provide protection to the most environmentally sensitive marine environments. In reviewing the following environmental documents, the Agency determined that the highest probability of direct environmental effects of produced water discharges is most prevalent in shallower waters:

EPA final report 440/4-85-002, Assessment of Environmental Fate and Effects of Discharges from Offshore Oil and Gas Operations, March 1985.

API Publication No. 4291, Effects of Oilfield Brine Effluent on Benthic Organisms in Trinity Bay, Texas.

API Project No. 248, Ecological Effects of Produced Water Discharges from Offshore Oil and Gas Production Platforms, by B.S. Middleditch, March 1984.

In the Gulf of Mexico, for example, species distribution data provided by the National Oceanic and Atmospheric Administration (NOAA) indicate that water depths of 20 meters or less encompass approximately 88 percent of the nursery areas for selected fish and invertebrates. The Agency projected that 124 new platforms would be built in 20 meters or less of water in the Gulf of Mexico.

The Agency also evaluated the Beaufort Sea, Norton Basin, Cook Inlet/Shelikof Strait, Bristol Bay, and the Gulf of Alaska in Alaska. EPA analyses indicated that a water depth of 10 meters or less (i.e., 10-meter isobath) in the Beaufort Sea; a 20-meter isobath in the Norton Basin; and a 50-meter isobath in Cook Inlet/Shelikof Strait, Bristol Bay, and the Gulf of Alaska would provide substantial protection of critical life stages of the commercial and subsistence species in each region.

For the California Coast, EPA's analyses indicate that the 50-meter isobath will protect the majority of the designated areas of biological significance. It will also protect most of the known nursery areas.

Along the Atlantic Coast, species distribution data were obtained from NOAA that indicate approximately 83 percent of the nursery areas for the selected fish and invertebrates are encompassed by water depths of 20 meters or less.

A zero discharge requirement for produced water would also achieve control of many nonconventional, toxic pollutants in addition to the 126 listed priority pollutants (See Appendix D of this document). An EPA survey of 10 production platforms in Louisiana [194] identified chemicals containing toxic or nonconventional, toxic pollutants in use on the platforms that were either present or likely to be present in produced water. These chemicals include biocides, coagulants, corrosion inhibitors, cleaners, dispersants, emulsion breakers, paraffin control agents, reverse emulsion breakers, and scale inhibitors. Detergents used to clean the platforms were also found in produced water.

DRILLING FLUIDS

Control and Treatment Options Considered

This following section presents the regulatory options considered for NSPS for drilling fluids. Because these options are the same as the options considered for BAT, the discussion of costs is presented in the BAT section for drilling fluids. Thus there are no NSPS costs or impacts incremental to BAT.

Option 1 - Toxicity Limitation. This option would result in the regulation of free oil, oil-based fluids, diesel oil, cadmium, mercury and the toxicity of the discharged drilling fluid. Most of these limitations are achieved by product substitution - specifically, through the use of water-based drilling fluids (i.e., generic muds), low toxicity specialty additives, the use of mineral oil instead of diesel oil for lubricity and spotting purposes, and use of barite with low toxic metals content.

Under this option the discharge of free oil would be prohibited, as in the existing BPT regulation. The discharge of oil-based drilling fluids would also be prohibited. Oil-based drilling fluids usually contain 50 or more percent of oil by volume. One method of compliance is substitution with less toxic water-based fluids.

The prohibition on the discharge of free oil for BPT effectively prohibits the discharge of oil-based drilling fluids. Therefore, any differential costs incurred to implement substitution of water-based for oil-based fluids is a cost attributable to compliance with BPT requirements. Moreover, in contrast to the BPT regulation, this NSPS option contains an explicit prohibition on the discharge of oil-based fluids in addition to the prohibition on discharges of free oil. The alternative to product substitution, i.e., use of water based mud systems, is to transport the spent mud system to shore for reconditioning, recovery and/or land disposal.

The prohibition on the discharge of oil-based drilling fluids is included in this option as an "indicator" of the toxic pollutants present in these fluids. These pollutants include: benzene, toluene, ethylbenzene, naphthalene and phenanthrene. The free oil discharge prohibition in BPT originally was imposed to prevent the discharge of oils in amounts that would cause a sheen on receiving waters and this limitation will continue.

The discharge of diesel oil, either as a component in an oil-based drilling fluid or as an additive to a water-based drilling fluid, would be prohibited under this option. Diesel oil would be regulated because it contains such toxic organic pollutants as benzene, toluene, ethylbenzene, naphthalene, and phenanthrene. The method of compliance with this prohibition is to use mineral oil instead of diesel oil for lubricity and spotting purposes. Mineral oil is a less toxic alternative to diesel oil and is available to serve the same operational requirements. Low toxicity mineral oils are also available as substitutes for diesel oil and continue to be developed for use in drilling fluids. However, mineral oil cannot necessarily be substituted into a product formulation tailored for diesel oil. Other adjustments in the product components may have to be made to accommodate mineral oil.

The purpose of the toxicity limitation for any spent drilling fluids which are to be discharged is to encourage the use of generic or water-based drilling fluids and the use of low-toxicity drilling fluid additives (i.e., product substitution). The basis for the toxicity (LC-50) limitation is the toxicity of the most toxic of the generic fluids. The most toxic generic fluid is potassium/polymer mud (see Table V-7). The imposition of an LC-50 toxicity limitation for all drilling fluids which are to be discharged would allow for use of any of the eight generic drilling fluids. Seven of the generic drilling fluids (i.e., all but potassium/polymer mud) could be supplemented with low-toxicity specialty additives and lubricity agents to meet operational requirements, and should still be able to comply with the LC-50 toxicity limitation prior to discharge. The potassium/polymer drilling fluid probably could not be supplemented with additives that exhibit a toxicity greater than the proposed LC-50 limitation because the LC-50 toxicity limitation is based upon the base formulation of this drilling fluid. However, industry operators and drilling fluid suppliers have indicated that potassium/polymer drilling fluid is seldom used. In drilling situations where there is no substitute for potassium/polymer drilling fluid for operational reasons, such a spent mud system would comply with the proposed LC-50 toxicity limitation (3 percent, diluted suspended particulate phase) only if any required lubricity agents (oils) or specialty additives are no more toxic than the base mud formulation. Such additives are available and continue to be developed. However, where the toxicity of the spent mud system exceeds the LC-50 toxicity limitation, the method of compliance with this option would be to transport the spent fluid system to shore for either reconditioning for reuse or land disposal.

The toxicity limitation would apply to any periodic surges of drilling fluid as well as to bulk discharges of drilling fluid systems. The term drilling fluid systems refers to the major types of muds used during the drilling of a single well. As an example, the drilling of a particular well used a spud mud for the first 200 feet, a seawater gel mud to a depth of 1,000 feet, a lightly treated lignosulfonic mud to 5,000 feet, and finally a freshwater lignosulfate mud system to a bottom hole depth of 15,000 feet. Typically, bulk discharges of 1,000 to 2,000 barrels of spent drilling fluids occur when such mud systems are changed or at the completion of a well.

For the purpose of self monitoring and reporting requirements in NPDES permits, it is intended that only samples of the spent drilling fluid system discharges be analyzed in accordance with the proposed bioassay method. These bulk discharges are the highest volume mud discharges and will contain all the specialty additives included in each mud system. Thus, spent drilling fluid system discharges are the most appropriate discharges for which compliance with the toxicity limitation should be demonstrated. In the above example, four such determinations would be necessary.

For determining the toxicity of the bulk discharge of mud used at maximum well depth, samples may be obtained at any time after 80 percent of actual well footage (not total vertical depth) has been drilled and up to and including the time of discharge. This would allow time for a sample to be collected and analyzed by bioassay and for the operator to evaluate the bioassay results so that the operator will have adequate time to plan for the final disposition of the spent drilling fluid system, e.g., if the bioassay test is failed, the operator could then anticipate and plan for transport of the spent drilling fluid system to shore in order to comply with the effluent limitation. However, the operator is not precluded from discharging a spent mud system prior to receiving analytical results. Nonetheless, the operator would be subject to compliance with the effluent limitations regardless of when self-monitoring analyses are performed. The prohibition on discharges of free oil, oil-based drilling fluids, and diesel oil would apply to all discharges of drilling fluid at any time.

Cadmium and mercury would be regulated at a level of 1 mg/kg, each, as a maximum ("not-to-exceed" value) on a dry weight basis in any spent drilling fluid system discharge. These two toxic metals would be regulated to control the metals content of the barite component of any drilling fluid discharges. The method of compliance with these limitations is product substitution. This involves use of barite from sources that either do not contain these metals or contain the metals at low enough levels such that resultant levels in the whole fluid system do not exceed the limitations.

The causes for noncompliance with the specific requirements of this option could include: inability to use a drilling fluid that can meet the proposed toxicity limitation, such as the need for an oil-based mud or a potassium/polymer mud with oil additives because of operational reasons, the need to add lubricity agents or other specialty additives to a mud system to meet particular operational requirements, or the unavailability of barite containing low toxic metals levels. However, as previously noted, BPT effectively prohibits the discharge of oil-based drilling fluids, and less toxic water-based fluids are available substitutes. Although the potassium/polymer mud represents the most toxic water-based fluid allowed for discharge, it is seldom used for offshore drilling purposes. However, potassium/polymer mud is used in Alaska where disposal alternatives are limited. It is also recognized that the availability of barite stocks containing low levels of trace metals could be limited at any given time due to market conditions. Nonetheless, the Agency does believe that sufficient sources of such barite do exist and can be directed to offshore drilling use in those cases where an operator intends to discharge drilling fluids. Mineral oil is an available alternative to diesel oil for use as a lubricant or spotting fluid. Although there are specialty additives for which less toxic substitutes have not been identified, the toxicity limitation is applied to the discharge of the entire drilling fluid system, and not to individual components. Thus, the Agency believes that only a limited number of offshore drilling operations would not be allowed to discharge spent drilling fluids due to violation of one or more of the requirements of this option. A conservative estimate is that, at most, ten percent of all spent drilling fluid systems would violate the proposed limitations and would have to be transported to shore to comply with this NSPS option.

Option 2 - Clearinghouse Approach. The effluent limitations to be imposed under Option 2 would be the same as those under Option 1. However, Option 2 would establish a different mechanism for determining compliance with the acute toxicity limitations. A central data base, or clearinghouse, would be developed and maintained by the Agency to collect and store information on toxicity and pollutant characteristics of drilling fluid formulations and specialty additives. The information could then be used by both permitting authorities and industry permittees for evaluating the acceptability of spent muds for discharge. The clearinghouse approach would allow an operator to determine, as early as possible, whether a specific formulation would likely comply with the discharge toxicity limitation or whether it would have to be transported to land for disposal.

The clearinghouse would be a central library of data that indexes pollutant characteristics for individual additives or formulations that an offshore operator, manufacturer, or supplier would submit to the Agency for consideration. The operator or supplier would conduct selected toxicity and chemical analyses on their products and provide this information to the Agency for quality assurance review and inclusion in the data base. The clearinghouse could then be used as a tool for estimating compliance with effluent limitations for drilling fluids, but would not function as a means of establishing or determining actual compliance with individual discharge permit limitations.

Option 3 - Zero Discharge. This option would require zero discharge for all drilling fluids, based upon transport of spent drilling fluids to shore for recovery, reconditioning for reuse, and/or land disposal, or transport to an approved ocean disposal site. This level of technology would result in no discharge of pollutants to surface waters except at approved ocean disposal sites.

Selected Option and Basis for Selection

EPA has selected Option 1 as the basis for proposed new source performance standards for drilling fluids. The proposed standards include the following limitations:

- A prohibition on the discharge of free oil, oil-based drilling fluids, and diesel oil, all considered as "indicators" of priority pollutants.
- A 96-hour LC-50 toxicity limitation on the discharged drilling fluids of no less than 3.0 percent by volume of the diluted suspended particulate phase.
- A maximum limitation (no single sample to exceed) for cadmium and mercury in the discharged drilling fluid of 1 mg/kg each, dry weight basis.

The prohibitions on the discharge of free oil, oil-based drilling fluids, and diesel oil are all intended to limit the oil content in drilling fluid wastestreams and, thereby, control the priority as well as conventional and nonconventional pollutants present in those oils. The pollutants "free oil," "oil-based drilling fluids," and "diesel oil" are each considered to be "indicators" of the priority pollutants present in these complex hydrocarbon mixtures used as additives to drilling fluids. These pollutants include: benzene, toluene, ethylbenzene, naphthalene and phenanthrene. The Agency's primary concern is controlling the priority pollutants in the oils although these prohibitions also will serve to control nonconventional and conventional pollutants. The Agency selected the "indicator" approach as an alternative to establishing limitations on each of the specific toxic and non-conventional pollutants present in these oil-contaminated wastestreams.

The sampling and analysis data demonstrate that when the amount of oil, especially diesel, is reduced in drilling fluid, the concentrations of priority pollutants and the overall toxicity of the fluid generally is reduced. The Agency has determined that control of the amount or type of oil present in drilling fluids with limitations on the three "indicators", free oil, oil-based drilling fluids and diesel oil, will provide a satisfactory level of control of the priority pollutants present in drilling fluids. This method of toxic regulation obviates the difficulties and costs of monitoring and analysis if limitations were established for each of the organic priority pollutants present in the drilling fluids.

The LC-50 toxicity limitation on the discharge of drilling fluids is to reduce the toxic constituents in the drilling fluid system. While the three indicator limitations on the amount or type of oil present in drilling fluids should significantly reduce the toxic pollutants present in drilling fluids, other additives such as mineral oil or some of the numerous specialty additives may greatly increase the toxicity of the drilling fluid. The toxicity is, in part, caused by the presence and concentration of priority pollutants. By establishing a toxicity limitation, the Agency believes that operators will consider toxicity in selecting additives and select the less toxic alternative. For instance, there can be a broad spectrum in the toxicity of various mineral oil sources. The Agency believes that the Clean Water Act authorizes the Agency to establish a toxicity limitation as an effluent limitation designed to control the chemical or toxic constituents of the discharge. The availability of a wide selection of additives makes product substitution the best available demonstrated technology for complying with the toxicity limitation. The Agency has considered the costs of product substitution and finds them to be acceptable for this industry, resulting in no barrier to future exploration and development. These standards are not expected to have any adverse non-water quality environmental impacts or increase in energy requirements. The generic drilling fluids list is a primary basis for both the prohibitions on the discharge of free oil and oil-based drilling fluids and the LC-50 limitation. As discussed in Section V, EPA has determined, through the NPDES permit process, that the eight generic water-based drilling fluids, whose formulations are presented in Table V-7 of this document, are adequate for virtually all drilling situations and are less toxic than oil-based drilling fluids. In order for a drilling fluid to be discharged, it must be no more toxic than the proposed LC-50 standard as determined with the Drilling Fluids Toxicity Test presented in Appendix C of this document.

Under this option, a drilling fluid can be discharged only if it does not contain additives that would cause its toxicity to exceed the toxicity of the most toxic generic mud. Further, EPA has determined that refined mineral oil is an adequate substitute for diesel oil since it is less toxic and operationally satisfactory. Accordingly, diesel oil would not be an allowable additive, either as a lubricity agent or spotting fluid, to a drilling fluid intended to be discharged. Mineral oil would be allowed as a lubricity agent and spotting fluid in the drilling fluid provided that its addition would not cause the toxicity of the discharged drilling fluid, including all other additives, to exceed the proposed LC-50 standard.

The limitations on cadmium and mercury, both priority pollutants, are intended to control the concentrations of toxic metals in barite, a major component of drilling fluids. As discussed above, these limitations would be met by product substitution.

In addition, the Agency is proposing a different definition of the term "no discharge of free oil" from that promulgated for the BPT regulation (44 FR 22075, April 13, 1979). The rationale for the proposed change is the same as that discussed in Section X. Also, a test procedure for determining compliance with this prohibition on free oil discharges is proposed. This test procedure is called the "static sheen test", and is presented in Appendix A of this document.

This NSPS option is the same as the proposed BAT option for drilling fluids, as discussed below. Therefore, there are no NSPS compliance costs or impacts incremental to BAT for drilling fluids.

Option 2 was not selected as the basis for NSPS at this time because the Agency does not anticipate such a "clearinghouse" program to be established prior to promulgation of NSPS. Development of listing methodologies and criteria and compilation of an adequate toxicity data base, which is central to the "clearinghouse approach" of Option 2, is estimated to take from three to five years. Such methodologies, criteria and data are essential for full implementation on a nationwide basis. The Agency has begun to investigate the requirements for management of a clearinghouse approach. Upon completion of this investigation and if the Agency decides to establish such a program, the Agency may propose to amend the toxicity approach to NSPS.

The Agency rejected Option 3, zero discharge, for implementation on a national basis for two major reasons. The Agency believes that the aggregate industry compliance costs of $126.3 million annually (1983 dollars) for transport and land disposal of all spent drilling fluids is too high. In addition, the Agency believes that there may be problems with adequate land availability for disposal of all spent drilling fluids. In part, this may be due to existing or future restrictions on the land disposal of drilling fluids under the requirements of hazardous waste disposal laws.

DRILL CUTTINGS

Control and Treatment Options Considered

The following section presents the regulatory options considered for NSPS for drill cuttings.

Option 1 - Product Substitution. This option would result in the regulation of free oil, oil-based fluids, and diesel oil in discharged drill cuttings. These limitations, as for the selected option for drilling fluids, are achieved by product substitution. Water-based drilling fluids would be substituted for oil-based fluids and mineral oil would be substituted for diesel oil. These three pollutant parameters would be regulated in a manner identical to that for the same pollutant parameters for drilling fluids Option 1 and the rationale for their regulation is also the same because the constituent of concern in the drill cuttings waste stream is the residual drilling fluid that adheres to the drill cuttings.

Option 2 - Product Substitution Plus Oil Limitation. This option would be equivalent to Option 1 plus a limitation on the allowable oil content of the discharged cuttings. The oil content limitation of 10 percent maximum by weight would be based upon water/detergent washer technology, as discussed in Section VII of this document. This "residual oil" limitation would be imposed as an indicator of toxic pollutants, specifically the priority organic pollutants in oils that are added to drilling fluid systems.

Option 3 - Zero Discharge. This option would require zero discharge of all drill cuttings, based upon transportation of drill cuttings to shore for land disposal or to an approved ocean disposal site. This option would result in no discharge of pollutants to surface waters except at approved ocean disposal sites.

Selected Option and Basis for Selection

The Agency selected Option 1 as the basis for proposed NSPS for drill cuttings. The requirements of Option 1 are comparable to those of the selected option for drilling fluids.

The Agency did not select Option 2 at this time because it believes that establishing an oil content limitation on drill cuttings may be redundant because the prohibition on the discharge of free oil in conjunction with the prohibition of cuttings from oil-based muds appears to be a more stringent limitation. While presently demonstrated cuttings washer technology will reduce residual oil content to less than ten percent by weight, the Agency's data base indicates that visible sheen can be caused by as little as one percent oil, by weight. Thus, the free oil discharge prohibition may be more stringent than any residual oil limitation that can be presently attained with cuttings washer technology that has been demonstrated on a full-scale basis. The Agency will collect and evaluate additional cuttings washer performance data, especially with respect to the use of mineral oil for lubricity and spotting purposes, to establish whether an oil content limitation is more stringent than the prohibition on the discharge of free oil.

The Agency rejected Option 3, zero discharge, because of high aggregate compliance costs and land availability problems as discussed below for drilling fluids BAT Option 3.

DECK DRAINAGE

As with BAT/BCT, the Agency is proposing to establish NSPS for deck drainage the same as the BPT level of control. This would result in a prohibition on the discharge of free oil. The technology basis is oil-water separation. The Agency is reserving coverage for all other pollutant parameters and characteristics for deck drainage pending additional data collection and analysis. This additional data will include toxic, nonconventional, and conventional pollutant information and control and treatment technology evaluation.

The method of determining compliance with the free oil prohibition is by the static sheen test discussed earlier and as presented in Appendix A of this document. Where deck drainage is collected and treated separately from produced water, the free oil prohibition would apply. However, where deck drainage is commingled and cotreated with produced water, the effluent limitations for produced water would apply to these two combined waste streams.

Because this proposed standard is equal to BAT/BCT, there are no incremental compliance costs due to NSPS.

SANITARY WASTES

The Agency is proposing to establish NSPS for sanitary wastes equal to the BAT/BCT level of control. This would result in: (1) a prohibition on the discharge of floating solids for facilities manned by nine or fewer persons or intermittently manned by any number of persons; and (2) an effluent standard for residual chlorine of 1 mg/l minimum and to be maintained as close as possible to 1 mg/l, for facilities continuously manned by ten or more persons. Because these proposed standards are equal to BAT/BCT, there are no incremental compliance costs due to NSPS.

DOMESTIC WASTES

The Agency is proposing to establish NSPS equal to the BCT level of control for domestic wastes. This would result in a prohibition on the discharge of floating solids. Since NSPS would equal BCT, no compliance costs incremental to BCT are associated with this standard.

PRODUCED SAND

The Agency is proposing to establish a prohibition on the discharge of free oil for produced sand under NSPS. The technology basis for this standard is water or solvent wash of produced sands prior to discharge, or transport of produced sand to shore for land disposal. The method of determining compliance with the free oil prohibitation is by the static sheen test as presented in Appendix A of this document. There are no compliance costs incremental to the proposed BAT limitation.

The Agency is reserving coverage for all other pollutant parameters and characteristics for produced sand pending additional data collection and analysis. This additional data will include toxic, non-conventional, and conventional pollutant information and control and treatment technology evaluation.

WELL TREATMENT FLUIDS

The Agency is proposing to establish a NSPS prohibition on the discharge of free oil from well treatment fluids as an "indicator" of specific toxic pollutants to reduce or eliminate the discharge of any toxic pollutants in the free oil to surface waters. These pollutants include: benzene, toluene, ethylbenzene, naphthalene, and phenanthrene. This is equal to the proposed BAT level of control, as discussed below. Therefore, there are no compliance costs incremental to BAT.

The Agency is reserving NSPS coverage of all other pollutants for well treatment fluids pending additional data collection and evaluation. This additional data will include toxic, nonconventional and conventional pollutant information and control and treatment technology evaluation.

REGULATORY BOUNDARIES

New source offshore oil production facilities located in or discharging to the following areas are subject to the zero discharge standard for produced water, depending upon water depth at the location of the facility or discharge. Unless otherwise stated below, the outer boundary for each designated area is the 200-mile boundary of the Fishery Conservation Zone.

Gulf of Mexico - Water Depth 20 Meters or Less

Extending from the inner boundary of the territorial seas offshore of Eastern Texas, Louisiana, Mississippi, Alabama, and Western Florida.

Atlantic Coast - Water Depth 20 Meters or Less

Extending from the inner boundary of the territorial seas offshore of the contiguous states between and including Maine and Florida

California Coast - Water Depth 50 Meters of Less

Extending offshore of California and bounded on the north by approximately 42°N latitude and bounded on the south by the U.S. - Mexico boundary.

Alaska

1. Gulf of Alaska - Water Depth 50 Meters or Less

It is bounded approximately on the west by 151° 55'W. longitude; thence east along 59°N latitude to 148°W longitude; thence south to 58°N latitude; thence east along 58°N latitude to 147°W longitude, thence south.

2. Cook Inlet/Shelikof Strait - Water Depth 50 Meters or Less

Lies east of 156°W longitude and north of 57°N latitude to the inner boundary of the territorial seas near Kalgin Island.

3. Bristol Bay/Aleutian Range - Water Depth 50 Meters or Less

   a. North Aleutian Basin: Lies in the eastern Bering Sea northwest of the Alaskan Peninsula and south of 59°N latitude. It is bounded on the west by 165°W longitude and in the east by the inner boundary of the territorial seas.

   b. St. George Basin - Water Depth of 50 Meters or Less

   Lies in the eastern Bering sea northwest of the Aleutian Islands chain and is bounded on the north by 59°N latitude and on the west by 174°W longitude from 59°N latitude to 56°N latitude; thence east to 171°W longitude, thence south. It is bounded on the east by 165°W longitude.

4. Norton Basin - Water Depth 20 Meters or Less

Lies south and southwest of the Seaward Peninsula. It is bounded on the south by 63°N latitude, on the west by the

U.S. Russia Convention Line of 1867, on the north by 65° 34'N latitude, and on the east by the inner boundary of the territorial seas.

5. Beaufort Sea - Water Depth 10 Meters or Less

Lies offshore of Alaska in the Beaufort Sea and the Arctic Ocean. It is bounded on the west by the Mineral Management Service Chukchi Sea planning area, extends eastward to the limit of U.S. jurisdiction, and on the south by the inner boundary of the territorial seas.

To determine water depth at a particular facility location, reference the most recent nautical charts or bathymetric maps with the smallest scale (highest resolution) available from the National Oceanic and Atmospheric Administration for the area of future development in question. Water depth is the mean lower low water depth indicated on the appropriate map for the location of the facility or discharge. Water depth at the facility is based upon the proposed location of the facility's well slot structure.

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252. Eastern Research Group, Inc., "Economic Impact Analysis of Proposed Effluent Guidelines Regulations for the Offshore Oil and Gas Industry," Prepared for U .S. EPA, August 1984.

X. BEST AVAILABLE TECHNOLOGY (BAT)

PRODUCED WATER

The Agency is reserving coverage of produced water for existing sources at this time. This is because the Agency lacks sufficient information to properly evaluate the technological feasibility and economic achievability of a reinjection requirement for existing sources. EPA is presently undertaking a comprehensive data collection effort to obtain industry profile information, retrofit costing information for reinjection, and information on the extent of biocide and other chemical usage for existing platforms. This information will be analyzed by the Agency to develop appropriate discharge regulations for the BAT level of control.

Because BAT is intended to control toxic and nonconventional pollutants, improved BPT or filtration technologies were rejected by the Agency for existing sources because these technologies primarily control conventional pollutants, and do not effect quantifiable reductions of toxic pollutants. The Agency will continue to consider a reinjection option for BAT as presented for NSPS above, including options based on variable water depths.

DRILLING FLUIDS

Control and Treatment Options Considered

Option 1 - Toxicity Limitation. This option is the same as NSPS Option 1 for drilling fluids. It would regulate the discharge of free oil, oil-based drilling fluids, diesel oil, cadmium, mercury and the toxicity of discharged drilling fluids. These limitations are achieved by product substitution - through the use of water-based drilling fluids (i.e., generic muds), low toxicity specialty additives, the use of mineral oil instead of diesel oil for lubricity and spotting purposes, and use of barite with low toxic metals content. The purpose and rationale for these effluent standards is the same as that presented above for NSPS.

This option would result in an annual cost of $26.3 million (1983 dollars) for an estimated 1166 wells. These costs are incremental to BPT requirements and are based upon the following: transport of ten percent of all spent drilling fluid systems either to shore for land disposal or to an approved ocean disposal site; a 15 percent increase in barite costs due to increased storage and handling costs and increased demand for barite with low toxic metals content; testing costs associated with the toxicity limitation and the mercury and cadmium effluent limitation; and monitoring costs. The differential cost of substituting mineral oil for diesel oil (approx. $1.90 per gallon inlcuding costs for storage and handling) is not attributable to the BAT option as an incremental cost to BPT. While BPT does not prohibit the discharge of diesel oil, the discharge of diesel oil in any significant amounts (i.e., one volume percent or more) would cause a sheen on receiving waters which would violate the BPT prohibition on the discharge of free oil. Therefore, the amount of mineral oil required to comply with a proposed prohibition on the discharge of diesel oil would be minimal, and the associated costs would be minimal.

Option 2 - Clearinghouse Approach. This option is the same as NSPS Option 2 for drilling fluids. It is based upon the establishment by EPA of a listing of drilling fluid formulations and additives that are considered acceptable for discharge.

Option 3 - Zero Discharge. This option is the same as NSPS Option 3 for drilling fluids. It would require zero discharge for all drilling fluids, based upon transport of spent drilling fluids to shore for recovery, reconditioning for reuse, land disposal, or transport to an approved ocean disposal site. This level of technology would result in no discharge of pollutants to surface waters, except at approved ocean disposal sites.

For the estimated 1166 wells drilled annually, this option would cost $126.3 million (1983 dollars). These compliance costs are incremental to BPT requirements, and reflect barging and monitoring costs.

This option would result in an annual reduction of the discharge of 6.2 million barrels of drilling fluids to surface waters.

Selected Option and Basis for Selection

EPA has selected Option 1 as the basis for proposed BAT for drilling fluids. BAT would include the same limitations as NSPS:

- o A prohibition on the discharge of free oil, oil-based drilling fluids, and diesel oil, all considered as "indicators" of toxic pollutants.
- o A 96-hour LC-50 toxicity limitation on discharged drilling fluids of no less than 3.0 percent by volume of the diluted suspended particulate phases.
- o A maximum limitation (no single sample to exceed) on the amount of cadmium and mercury in discharged drilling fluids of 1 mg/kg each, dry weight basis.

Options 2 and 3 were rejected for the same reasons as discussed above for NSPS.

As with NSPS, the prohibitions on oil will be used as "indicators" of toxic pollutants. These pollutants include: benzene, toluene, ethylbenzene, naphthalene, and phenanthrene. The Agency believes it is appropriate to establish these prohibitions as BAT toxic limitations. The primary purpose is to control the priority pollutants present in the oils. Control of the oil content in fluids could also be achieved through a numeric limitation on the conventional pollutant "oil and grease." In fact, the Agency has included the prohibition on the discharge of free oil as a BCT limitation in recognition of the complex nature of the oils present in drilling fluids. However, the Agency's decision to establish BAT limitations through the three oil prohibitions was based on the consideration that it would be less difficult and costly to comply with these three "indicator" limitations than numeric limitations on each of the organic priority pollutants present in the oils. This decision to establish limitations on oils as indicators of priority pollutants is consistent with the Agency's listing of "oil and grease" as a conventional pollutant. (44 FR 44501). The Agency solicits comments on its decision to establish these indicator pollutant limitations as BAT rather than setting numeric limitations on the specific organic priority pollutants. Since the oils would be considered BAT toxic indicators, such limitations would not be subject to Section 301(c) or Section 301(g) modifications.

Related to this option, the Agency is proposing to amend the current definition of the term "no discharge of free oil." The current definition of "no discharge of free oil" defines the term to mean "that a discharge does not cause a film or sheen upon or a discoloration on the surface of the water or adjoining shorelines or cause a sludge or emulsion to be deposited beneath the surface of the water or upon adjoining shorelines."

The amended definition is accompanied by a test procedure for determining compliance with the prohibition on free oil discharges. This test is the "static sheen test" presented in Appendix A of this document. This method would apply to the same waste streams that are regulated by the existing BPT regulations, i.e., deck drainage, drilling fluids, drill cuttings, and well treatment fluids.

The compliance monitoring procedure previously required by permits was a visual inspection of the receiving water after discharge. However, since the intent of the limitation is to prohibit discharges containing free oil that will cause a sheen, the method of determining compliance should examine oil contamination prior to discharge. Also, concerns have been raised that the intent of the existing definition of "no discharge of free oil" may be violated too easily for the limitation to be effective. Violations which may result from intentional or unintentional actions include the use of emulsifiers or surfactants, discharges that occur under poor visibility conditions (i.e., at night or during stormy weather), and discharges into heavy seas, which are common in offshore areas. Additionally, concerns have been expressed over the utility of the visual observation of receiving water compliance monitoring procedure for certain discharges during ice conditions as in Alaskan operations. These include above-ice discharges where the receiving water would be covered with broken or solid ice, and below-ice discharges where the effluent stream would be obscured.

To correct for these monitoring problems, the Agency developed an alternative compliance test, the Static Sheet Test, which is presented in Appendix A of this document. The alternative test continues the visual observation for sheen, but provides for testing before discharge using laboratory procedures. The test is conducted by adding samples of the effluent stream into a container in which the sample is mechanically mixed with a specific proportion of seawater, allowed to stand for a designated period of time, and then viewed for a sheen.

Since the intent of a "no discharge of free oil" limitation is to prevent the occurrence of a sheen on the receiving water, the new test method will prevent the discharge of fluids that will cause such a sheen.

DRILL CUTTINGS

Control and Treatment Options Considered

Option 1 - Product Substitution. Option 1 is the same as NSPS Option 1 for drill cuttings. It would result in the prohibited discharge of free oil, oil-based drilling fluids, and diesel oil with discharged drill cuttings. These limitations, as for the selected option for drilling fluids, are achieved by product substitution. The rationale for these limitations is also the same as for drilling fluids Option 1 because the constituent of concern in the drill cuttings waste stream is the residual drilling fluid that mixes with and adheres to the drill cuttings.

For the estimated 1166 wells drilled annually, this option would result in an estimated annual barging and monitoring cost of $8.6 million (1983 dollars). No investment costs are expected to occur from this option. This option would result in an estimated annual reduction of at least 1.3 million pounds of oil otherwise discharged to surface waters.

Option 2 - Product Substitution plus Oil Limitation. Option 2 is equivalent to Option 1 plus a limitation on the allowable oil content of the discharged cuttings. This option is the same as NSPS Option 2 for drill cuttings. The oil content limitation of 10 percent maximum by weight would be based upon drill cuttings water/detergent washer technology, as discussed in Section X of this document.

Option 3 - Zero Discharge. Option 3 would require zero discharge of all drill cuttings, based upon transport of drill cuttings to shore for land disposal, or transportation to an approved ocean disposal site. This option would result in no discharge of pollutants to surface waters, except at approved ocean disposal sites. This option is the same as NSPS Option 3 for drill cuttings.

For the estimated 1166 wells drilled annually, this option would result in annual monitoring and barging costs of $77.1 million (1983 dollars). This option would result in an annual reduction of 1.7 million barrels of drill cuttings discharged to surface waters.

Selected Option and Basis for Selection

The Agency selected Option 1 as the basis for proposed BAT for drill cuttings. The requirements of Option 1 are comparable to those of the selected option for drilling fluids. This option is based on product substitution which is both a technologically feasible and economically achievable means for compliance by the industry.

The Agency is not selecting Option 2 at this time because it believes, as discussed above for NSPS, that establishing an oil content limitation on drill cuttings may be redundant because the prohibition on the discharge of free oil appears to be a more stringent limitation. The Agency will collect and evaluate additional cuttings washer performance data, especially with respect to the use of mineral oil for lubricity and spotting purposes, to establish whether an oil content limitation is more stringent than the free oil limitation.

The Agency rejected Option 3, zero discharge, because of high aggregate compliance costs and concern for adequate land availability for disposal as discussed above for NSPS.

DECK DRAINAGE

The Agency is proposing to establish BAT for deck drainage equal to the BPT level of control. This would result in a prohibition on the discharge of free oil to reduce or eliminate the discharge of any toxic pollutants in the free oil to surface waters. The technology basis is oil-water separation. BAT compliance costs incremental to BPT consist of additional compliance monitoring expenditures of $1.09 million (1983 dollars) annually, reflecting use of the proposed static sheet test to determine compliance with the prohibition on the discharge of free oil.

The Agency is reserving coverage of all other toxic and nonconventional pollutant parameters and characteristics for deck drainage pending additional data collection and analysis. This additional data will include toxic pollutant information and control and treatment technology evaluation.

SANITARY WASTES AND DOMESTIC WASTES

The Agency is not proposing to establish BAT effluent limitations for these waste streams because there have been no toxic or non-conventional pollutants of concern identified in sanitary or domestic wastes.

PRODUCED SAND

The Agency is proposing to establish a BAT prohibition on the discharge of free oil for produced sand as an "indicator" to reduce or eliminate the discharge of any toxic pollutants in the free oil to surface waters. The technology basis for this limitation is water and/or solvent wash of produced sands prior to discharge, or transport of produced sand to shore for land disposal. Because this waste stream is of low volume and because most facilities currently practice either washing or land disposal, the Agency did not attribute any compliance costs to this proposed limitation, except for nominal compliance monitoring expenses to perform the static sheen test to determine the presence of free oil.

The Agency is reserving coverage of all other toxic and non-conventional pollutant parameters and characteristics for produced sand pending additional data collection and analysis. This additional data will include toxic pollutant information and control and treatment technology evaluation.

WELL TREATMENT FLUIDS

The Agency is proposing to establish a BAT prohibition on the discharge of free oil for well treatment fluids as an "indicator" to reduce or eliminate the discharge of any toxic pollutants in the free oil to surface water. This is equal to the BPT level of control. Therefore, there are no compliance costs incremental to BPT, except for nominal compliance monitoring expenses to perform the static sheen test to determine the presence of free oil.

The Agency is reserving BAT coverage of all other pollutants and characteristics for well treatment fluids pending additional data collection and evaluation. This additional data will include toxic and nonconventional pollutant information and control and treatment technology evaluation.

XI. BEST CONVENTIONAL TECHNOLOGY (BCT)

The 1977 amendments added section 301(b)(4)(E) to the Act, establishing "best conventional pollutant control technology" (BCT) for discharges of conventional pollutants from existing industrial point sources. Conventional pollutants are those defined in section 304(b)(4) - BOD, TSS, fecal coliform and pH -and any additional pollutants defined by the Administrator as "conventional." On July 30, 1979, EPA designated "oil and grease" as a conventional pollutant (44 FR 44501).

BCT is not an additional limitation; rather it replaces BAT for the control of conventional pollutants. BCT requires that limitations for conventional pollutants be assessed in light of "cost-reasonableness." EPA published proposed rules for BCT on October 29, 1982 (47 FR 49176). These proposed rules set forth a revised procedure which includes two tests to determine the reasonableness of costs incurred to comply with candidate BCT technologies. These cost tests are the "POTW test" and the "industry cost test." On September 20, 1984, EPA published a "notice of data availability" concerning the proposed BCT regulations (49 FR 37046).

PRODUCED WATER

Control and Treatment Options Considered

EPA examined the three treatment options for removing conventional pollutants from produced water in relation to the proposed BCT methodology.

Option 1 - Improved Performance of BPT. This option would require effluent limitations based on the improved performance of BPT technology. As presented above for NSPS option (a), this level of technology would result in additional reductions of oil and grease beyond the BPT level of control. A discharge limitation of 59 mg/l maximum (no single sample to exceed) for oil and grease would result from this option.

Option 2 - Filtration On Site. This option would require effluent limitations based on granular media filtration as an add-on technology to BPT. Filtration equipment would be installed on the platform with the treated effluent being discharged at the platform. This level of technology would result in additional reductions of conventional pollutants beyond the BPT level of control. Effluent limitations of 20 mg/l monthly average and 30 mg/l daily maximum for oil and grease would result from this option.

Option 3 - Filtration Onshore. This option is the same as Option 2 except it is applicable to facilities which presently separate produced water from hydrocarbon product at the platform, pipe the produced water to shore for treatment to meet BPT effluent limitations, and discharge the treated effluent to surface waters.

Selected Option and Basis for Selection

The Agency rejected the options presented above and is proposing to establish BCT for produced water at the BPT level of control. This would result in effluent limitations of 48 mg/l monthly average and 72 mg/l daily maximum for oil and grease, based upon oil-water separation technologies. The Agency rejected Options 1 through 3 because they all fail the first part of the Agency's proposed BCT cost test (the "POTW test").

For Option 1, the Agency was unable to directly perform the POTW test because the Agency lacks sufficient information to accurately estimate the incremental cost of improved BPT performance (see Section IX NSPS Produced Water Control and Treatment Options, above); this cost is necessary in order to perform the POTW test. Therefore, the Agency analyzed this option by determining the maximum dollar expenditure per day that model platforms could incur to implement this option without exceeding the POTW test benchmark.

The maximum cost per pound of conventional pollutant removal whereby the "POTW test" will be passed is presented in the BCT "notice of data availability" referenced above. These maximum costs were used to calculate the total dollars that could be expended at each of the 32 model platforms, discussed in Section VIII, to comply with this option and still pass the "POTW test." This was accomplished by multiplying the pounds of conventional pollutants that would be removed by BCT Option 1 technology for each of the 32 model platforms developed for this study by the maximum cost per pound presented in the "notice of data availability."

This total cost for each model platform ranged from $0.79 per day for the smallest platform to $182 per day for the largest platform. The Agency believes that the cost of implementing Option 1 is minimal, although not as low as the range of daily costs presented above. Therefore, the Agency rejected Option 1 because it fails the POTW cost test.

For Options 2 and 3, the Agency calculated compliance costs (incremental to BPT) for each of 32 model platforms and then performed the POTW test for each model size platform. The range in costs per pound of conventional pollutant removed beyond BPT for Options 2 and 3 based on model platform size, is as follows:

	Lowest Cost $/lb Removed (1980 dollars)	Highest Cost $/lb Removed (1980 dollars)
Option 2	64	71
Option 3	54	63

These costs were compared with the fourth quarter, 1980 POTW proposed benchmark of $1.04 per pound of conventional pollutant removed; the POTW test failed for Options 2 and 3 for all model platforms. Therefore, EPA rejected these options for the BCT level of control. The Agency intends to evaluate reinjection technology for BCT after collection of certain additional technology and cost information prior to promulgation of the final regulations. The Agency may also re-evaluate the proposed BCT limitations for produced water when the final BCT methodology is promulgated.

DRILLING FLUIDS, DRILL CUTTINGS, DECK DRAINAGE AND WELL TREATMENT FLUIDS

With one exception, the Agency is reserving BCT requirements for drilling fluids, drill cuttings, deck drainage and well treatment fluids until final promulgation of the general BCT methodology. The exception is a prohibition on the discharge of free oil. This limitation is equal to the BPT level of control for these waste streams. Therefore, no incremental costs are associated with this proposed BCT limitation. Because BCT is proposed to be equal to BPT, the free oil discharge prohibition will pass any BCT methodology adopted. When the final BCT methodology is promulgated, the Agency may propose to establish BCT limitations for other conventional pollutants for these waste streams. At this time, the Agency is soliciting comment on what pollutants in drilling fluid and drill cuttings waste streams should be considered conventional pollutants. Specifically, the Agency solicits comments on whether the solids components of the fluids and cuttings should be considered total suspended solids.

DOMESTIC AND SANITARY WASTES

The Agency is proposing BCT coverage for sanitary and domestic wastes equal to the BPT level of control. The Agency is proposing a residual chlorine effluent limitation for facilities continuously manned by 10 or more persons of 1 mg/l minimum and to be maintained as close to this level as possible in sanitary discharges. Residual chlorine is being treated as a BCT parameter because its purpose is to control the conventional pollutant fecal coliform.

The proposed BCT limitation for domestic wastes from all facilities and sanitary wastes from facilities continuously manned by 9 or fewer persons or manned intermittently by any number of persons is "no discharge of floating solids." No compliance costs incremental to BPT are associated with the proposed BCT limitations. Since no additional costs will be incurred these limitations pass the BCT cost tests.

PRODUCED SAND

With one exception, the Agency is reserving BCT coverage for produced sand until the promulgation of the final BCT methodology. The Agency is proposing a BCT limitation that would prohibit the discharge of free oil for produced sand discharges. As discussed above for BAT, this limitation would result in negligible compliance costs.

XII. BEST MANAGEMENT PRACTICES

Section 304(e) of the Clean Water Act authorizes the Administrator to prescribe "best management practices" ("BMP") to control "plant site runoff, spillage or leaks, sludge or waste disposal, and drainage from raw material storage." Section 402(a)(1) and NPDES regualtion (40 CFR 122) also provide for best management practices to control or abate the discharge of pollutants when numeric effluent limitations are infeasible. However, the Administrator may prescribe BMP's only where he finds that they are needed to prevent "significant amount" of toxic or hazardous pollutants from entering navigable waters.

In the offshore oil and gas industry there are various types of wastes that may be affected by the application of BMP's in NPDES permits. These include deck drainage and leaks and spoils from various sources. The amount of contaminated deck drainage can be decreased considerably if proper segregation is practiced. "Clean" deck drainage should be segregated from sources of contamination. Many sources exist on an offshore platform where leaks or spillages could occur. The areas should be managed so that all leakages and/or spills are contained and not discharged overboard.

Good operation and maintenance practices reduce waste flows and improve treatment efficiencies, as well as reducing the frequency and magnitude of system upsets. Some examples of good offshore operation are:

1. Separation of waste crankcase oils from deck drainage collection systems.

2. Minimization of wastewater treatment system upsets by the controlled usage of deck washdown detergents.

3. Reduction of oil spillage through the use of good prevention techniques such as drip pans and other handling and collection methods.

4. Elimination of oil drainage from pump bearings and/or seals by directing the drainage to the crude oil processing system.

5. If oil is used as a spotting fluid, careful attention to the operation of the drilling fluid system could result in the segregation from the main drilling fluid system of the spotting fluid and the drilling fluid that has been contaminated by the spotting oil. Once segregated, the contaminated drilling fluid can be disposed of in an environmentally acceptable manner.

Proper initial engineering of the various systems is essential to proper operation and ease of maintenance. The use of spare equipment is a requirement for continual operation when breakdowns occur. Selection of proper treatment chemicals, to insure optimum pollutant removals, is essential. Alarms should be provided to make the operator aware of off-normal conditions so corrective action can be taken.

Careful planning, good engineering and a commitment on the part of the operating, maintenance and management personnel are needed to ensure that the full benefits of all pollution reduction facilities are realized.

6. Careful application of drill pipe dope to minimize contamination of rceiving water and drilling muds. Pipe dope can contribute high amounts of lead and probably other metals to discharged muds.

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XV. GLOSSARY AND ABBREVIATIONS

Act - The Clean Water Act.

Air/Gas Lift - Lifting of liquids by injection of air or gas directly into the well.

Annulus or Annular Space - The space between the drill stem and the wall of the hole or casing.

AOGA - Alaskan Oil and Gas Association.

API - American Petroleum Institute.

API Gravity - Gravity (weight per unit of volume) of crude oil as measured by a system recommended by the API.

Attapulgite Clay - A colloidial, viscosity-building clay used principally in salt water muds. Attapulgite is a hydrous magnesium aluminum silicate.

Back Pressure - Pressure resulting from restriction of full natural flow of oil or gas.

Barite - Barium sulfate. An additive used to weight drilling mud.

Barrel - 42 United States gallons at 60 degrees Fahrenheit.

BAT - The best available technology economically achievable, under Section 304(b)(2)(B) of the Act.

BCT - The best conventional pollutant control technology.

BDT - The best available demonstrated control technology processes, operating methods, or other alternatives, including where practicable, a standard permitting no discharge of pollutants under Section 306(a)(1) of the Act.

Bentonite - A clay additive used to increase viscosity of drilling mud.

Blowcase - A pressure vessel used to propel fluids intermittently by pneumatic pressure.

Blowout - A wild and uncontrolled flow of subsurface formation fluids at the earth's surface.

Blowout Preventer (BOP) - A device to control formation pressures in a well by closing the annulus when pipe is suspended in the well or by closing the top of the casing at other times.

BMP - Best management practices under Section 304(e) of the Act.

BOD - Biochemical oxygen demand.

BPT - The best practicable control technology currently available, under Section 304(b)(1) of the Act.

Bottom-Hole Pressure - Pressure at the bottom of a well.

Brackish Water - Water containing low concentrations of any soluble salts.

Brine - Water saturated with or containing a high concentration of common salt (sodium chloride); also any strong saline solution containing such other salts as calcium chloride, zinc chloride, calcium nitrate, etc.

BS&W - Bottom Sediment and water carried with the oil. Generally, pipeline regulation limits BS&W to 1 percent of the volume of oil.

Casing - Large steel pipe used to "seal off" or "shut out" water and prevent caving of loose gravel formations when drilling a well. When the casings are set, drilling continues through and below the casing with a smaller bit. The overall length of this casing is called the string of casing. More than one string inside the other may be used in drilling the same well.

Centrifuge - A device for the mechanical separation of solids from a liquid. Usually used on weighted muds to recover the mud and discard solids. The centrifuge uses high-speed mechanical rotation to acheive this separation as distinguished from the cyclone-type separator in which the fluid energy alone provides the separating force.

Chemical-Electrical Treater - A vessel which utilizes surfactants, other chemicals and an electrical field to break oil-water emulsions.

Choke - A device with either a fixed or variable aperture used to release the flow of well fluids under controlled pressure.

Christmas Tree - Assembly of fittings and valves at the top of the casing of an oil well that controls the flow of oil from the well.

Circulate - The movement of fluid from the suction pit through pump, drill pipe, bit annular space in the hole and back again to the suction pit.

Clean Water Act - The Federal Water Pollution Control Act Amendments of 1972 (33 U.S.C. 1251 et sea.), as amended by the Clean Water Act of 1977 (Pub. L. 95-217).

Closed-In - A well capable of producing oil or gas, but temporarily not producing.

COD - Chemical oxygen demand.

Condensate - Hydrocarbons which are in the gaseous state under reservoir conditions but which become liquid either in passage up the hole or at the surface.

Connate Water - Water that probably was laid down and entrapped with sedimentary deposits as distinguished from migratory waters that have flowed into deposits after they were laid down.

Cuttings - Small pieces of formation that are the result of the chipping and/or crushing action of the bit.

Cyclone - Equipment, usually cyclone type, for removing drilled sand from the drilling mud stream and from produced fluids.

Deck Drainage - Any waste resulting from deck washings, spillage, rainwater, and runoff from gutters and drains including drip pans and work areas within facilities addressed by this document.

Derrick and Substructure - Combined foundation and overhead structure to provide for hoisting and lowering necessary to drilling.

Desilter - Equipment, normally cyclone type, for removing extremely fine drilled solids from the drilling mud stream.

Development Facility - Any fixed or mobile structure addressed by this document that is engaged in the drilling and completion of productive wells.

Diesel Oil - The grade of distillate fuel oil, as specified in the American Society for Testing and Materials' Standard Specification D975-81, that is typically used as the continuous phase in conventional oil-based drilling fluids.

Differential Pressure Sticking - Sticking which occurs because part of the drill string (usually the drill collars) becomes embedded in the filter cake resulting in a non-uniform distribution of pressure around the circumference of the pipe. The conditions essential for sticking require a permeable formation and a pressure differential across a nearly impermeable filter cake and drill string.

Disposal Well - A well through which water (usually salt water) is returned to subsurface formations.

Domestic Waste - Materials discharged from sinks, showers, laundries, and galleys located within facilities addressed by this document.

Drill Cuttings - Particles generated by drilling into subsurface geologic formations and carried to the surface with the drilling fluid.

Drilling Fluid - The circulating fluid (mud) used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure. A water-base drilling fluid is the conventional drilling mud in which water is the continuous phase and the suspending medium for solids, whether or not oil is present. An oil-base drilling fluid has diesel, cruide, or some other oil as its continuous phase with water as the dispersed phase.

Drill Pipe - Special pipe designed to withstand the torsion and tension loads encountered in drilling.

Dump Valve - A mechanically or pneumatically operated valve used on separator, treaters, and other vessels for the purpose of draining, or "dumping" a batch of oil or water.

Emulsion - A substantially permanent heterogenous mixture of two or more liquids (which are not normally dissolved in each other, but which are) held in suspension or dispersion, one in the other, by mechanical agitation or, more frequently, by adding small amounts of substances known as emulsifiers. Emulsions may be oil-in-water, or water-in-oil.

EPA - United States Environmental Protection Agency.

Exploration Facility - Any fixed or mobile structure addressed by this document that is engaged in the drilling of wells to determine the nature of potential hydrocarbon reservoirs.

Field - The area around a group of producing wells.

Flocculation - The combination or aggregation of suspended solid particles in such a way that they form small clumps or tufts resembling wool.

Flowing Well - A well which produces oil or gas without any means of artificial lift.

Fluid Injection - Injection of gases or liquids into a reservoir to force oil toward and into producing wells. (See also "Water Flooding.")

Formation - Various subsurface geological strata penetrated by well bore.

Formation Damage - Damage to the productivity of a well resulting from invasion of mud particles into the formation.

Fracturing - Application of excessive hydrostatic pressure which fractures the well bore (causing lost circulation of drilling fluids).

Freewater Knockout - An oil/water separation tank at atmospheric pressure.

Gas Lift - A means of stimulating flow by aerating a fluid column with compressed gas.

Gas-Oil Ratio - Number of cuic feet of gas produced with a barrel of oil.

Gathering Line - A pipeline, usually of small diameter, used in gathering crude oil from the oil field to a point on a main pipeline.

Gel - A term used to designate highly colloidal, high-yielding, viscosity-building commercial clays, such as bentonite and attapulgite clays.

GC - Gas chromatography.

Gun Barrel - An oil-water separation vessel.

Header - A section of pipe into which several sources of oil, such as well streams, are combined.

Heater-Treater - A vessel used to break oil water emulsion with heat.

Hydrocarbon Ion Concentration - A measure of the acidity or alkalinity of a solution, normally expressed as pH.

Hydrostatic Head - Pressure which exists in the well bore due to the weight of the column of drilling fluid; expressed in pounds per square inch (psi).

Inhibitor - An additive which prevents or retards undesirable changes in the product. Particularly, oxidation and corrosion; and sometimes parrafin formation.

Invert Oil Emulsion Drilling Fluid - A water-in-oil emulsion where fresh or salt water is the dispersed phase and diesel, crude, or some other oil is the continuous phase. Water increases the viscosity and oil reduces the viscosity.

Killing a Well - Bringing a well under control that is blowing out. Also, the procedure of circulating water and drilling fluids into a completed well before starting well servicing operations.

Location (Drill Site) - Place at which a well is to be or has been drilled.

96-hr LC-50 - The concentration of a test material that is lethal to 50 percent of the test organisms in a bioassay after 96 hours of constant exposure.

M10 - Those offshore facilities continuously manned by ten (10) or more persons.

M9IM - Those offshore facilities continuously manned by nine (9) or fewer persons or only intermittently manned by any number of persons.

Mud Pit - A steel or earthen tank which is part of the surface drilling mud system.

Mud Pump - A reciprocating, high pressure pump used for circulating drilling mud.

Multiple Completion - A well completion which provides for simultaneous production from separate zones.

NPDES Permit - A National Pollutant Discharge Elimination System permit issued under Section 402 of the Act.

NRDC - Natural Resources Defense Council.

NSPS - New source performance standards under Section 306 of the Act.

OOC - Offshore Operators Committee.

PESA - Petroleum Equipment Suppliers Association.

Packer Fluid - Any fluid placed in the annulus between the tubing and casing above a packer. Along with other functions, the hydrostatic pressure of the packer fluid is utilized to reduce the pressure differentials between the formation and the inside of the casing and across the packer itself.

Pressure Maintenance - The amount of water or gas injected vs. the oil and gas production so that the reservoir pressure is maintained at a desired level.

Priority Pollutants - The 65 pollutants and classes of pollutants declared toxic under Section 307(a) of the Act. Appendix C contains a listing of specific elements and compounds.

Production Facility - Any platform or fixed structure addressed by this document that is used for active recovery of hydrocarbons from producing formations.

Produced Water - The water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas, and can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process.

Produced Sand - Slurried particles used in hydraulic fracturing and the accumulated formation sands and scale particles generated during production.

RCRA - Resource Conservation and Recovery Act (Pub. L. 94-580) of 1976. Amendments to Solid Waste Disposal Act.

Rank Wildcat - An exploratory well drilled in an area far enough removed from previously drilled wells to preclude extrapolation of expected hole conditions.

Reservoir - Each separate, unconnected body of producing formation.

Rotary Drilling - The method of drilling wells that depends on the rotation of a column of drill pipe with a bit at the bottom. A fluid is circulated to remove the cuttings.

Sanitary Waste - Human body waste discharged from toilets and urinals located within facilities addressed by this document.

Separator - A vessel used to separate oil and gas by gravity.

Shaleshaker - Mechanical vibrating screen to separate drilled formation cuttings carried to surface with drilling mud.

Shut In - To close valves on a well so that it stops producing; said of a well on which the valves are closed.

Skimmer - A settling tank in which oil is permitted to rise to the top of the water and is then taken off.

SPCC - A spill prevention control and countermeasure plan required under Section 311(j) of the Act.

Spot - The introduction of oil to a drilling fluid system for the purpose of freeing a stuck drill bit or string.

Stripper Well (Marginal Well) - A well which produces such small volume of oil that the gross income therefrom provides only a small margin of profit or, in many cases, does not even cover actual cost of production.

Stripping - Adding or removing pipe when well is pressured without allowing vertical flow at top of well.

TDS - Total Disolved Solids.

Territorial Seas - The belt of the seas measured from the line of ordinary low water along that portion of the coast which is in direct contact with the open sea and the line marking the seaward limit of inland waters, and extending seaward a distance of three miles.

TOC - Total Organic Carbon.

Total Depth (T.D.) - The greatest depth reached by the drill bit.

Treater - Equipment used to break an oil - water emulsion.

TSS - Total Suspended Solids.

USCG - United States Coast Guard.

USGS - United States Geological Survey.

Water Flooding - Water is injected under pressure into the formation via injection wells and the oil is displaced toward the producing wells.

Well Completion - In a potentially productive formation, the completion of a well in a manner to permit production of oil; the walls of the hole above the producing layer (and within it if necessary) must be supported against collapse and the entry into the well of fluids from formations other than the producing layer must be prevented. A string of casing is always run and cemented, at least to the top of the producing layer, for this purpose. Some geological formations require the use of additional techniques to "complete" a well such as casing the producing formation and using a "gun perforator" to make entry holes, the use of slotted pipes, consolidating sand layers with chemical treatment, and the use of surface-actuated underwater robots for offshore wells.

Well Head - Equipment used at the top of a well, including casing head, tubing head, hangers, and Christmas Tree.

Well Treatment Fluids - Those fluids used in stimulating a hydrocarbon-bearing formation or in completing a well for oil and gas production, and drilling fluids used in reworking a well to increase or restore productivity.

Wildcat Well - A well drilled to test formations nonproductive within a 1-mile radius of previously drilled wells. It is expected that probable hole conditions can be extrapolated from previous drilling experience data from that general area.

WOGA - Western Oil and Gas Association.

Workover - To clean out or otherwise work on a well in order to increase or restore production.

APPENDIX A - STATIC SHEEN TEST (ANALYTICAL PROTOCOL)

1. Scope and Application

This method is to be used as a compliance test for the "no discharge of free oil" requirement for discharges of drilling fluids, drill cuttings, deck drainage and produced sand. Free oil refers to any oil contained in a waste stream that when discharged will cause a film or sheen upon or a discoloration of the surface of the receiving water.

2. Summary of Method

Samples of drilling fluid and deck drainage (0.15 mL and 15 mL) and samples of drill cuttings and produced sand (1.5 g and 15 g, wet weight basis) are introduced into ambient seawater in a container having an air to liquid interface area of 1000 cm2. Samples are dispersed within the container and observations made no more than 1 hour later to ascertain if these materials cause a sheen, irridescence, gloss, or increased reflectance on the surface of the test seawater. The occurrence of any of these visual observations will constitute a demonstration that the tested material contains "free oil", and therefore, results in a prohibition on its discharge into receiving waters.

3. Interferences

Residual "free oil" adhering to sampling containers, the magnetic stirring bar used to mix drilling fluids, and the stainless steel spatula used to mix drill cuttings will be the principal sources of contamination if improperly washed and cleaned equipment are used for the test. The use of disposable equipment minimizes the potential for similar contamination from pipets and the test container.

4. Apparatus materials and Reagents

4.1 Apparatus

4.1.1 Sampling containers - 1 liter polyethylene beakers

4.1.2 Graduated cylinder - 100 mL graduated cylinder required only for operations where predilution of mud discharges is required.

4.1.3 Plastic disposable weighing boats

4.1.4 Triple beam scale

4.1.5 Disposable pipets - 1 mL and 25 mL disposable pipets

4.1.6 Magnetic stirrer and stirring bar

4.1.7 Stainless steel spatula

4.1.8 Test container - open plastic container whose internal cross-section parallel to its opening has an area of 1000 ± 50 cm^2, and a depth of no more than 30 cm.

4.2 Materials and Reagents

4.2.1 Plastic liners for the test container - Oil free, heavy duty plastic trash can liners that do not inhibit the spreading of an oil film. Liners must be of a sufficient size to completely cover the interior surface of the test container. Permittees must determine an appropriate local source of liners that do not inhibit the spreading of 0.05 mL diesel fuel added to the lined test container under the test conditions and protocol described below.

4.2.2 Ambient receiving water

5. Calibration

None currently specified

6. Quality Control Procedures

None currently specified

7. Sample Collection and Handling

7.1 Sampling containers must be thoroughly washed with detergent, rinsed a minimum of 3 times with fresh water, and allowed to air dry before samples are collected.

7.2 Samples of drilling fluid must be obtained once per day from the active mud pit; the sample volume should range between 200 mL and 500 mL.

7.3 Samples of drill cuttings and produced sand must be obtained from each type of solids control equipment from which discharges occur on any given day prior to addition of any washdown water; samples should range between 200 and 500 grams.

7.4 Samples of deck drainage must be obtained from the deck drainage holding facility prior to discharge; the sample volume should range between 200 mL and 500 mL.

7.5 Samples must be tested no later than 1 hour after collection.

7.6 Drilling fluid samples must be mixed in their sampling containers for 5 minutes prior to testing using a magnetic bar stirrer. If predilution is imposed as a permit condition, the sample must be mixed at the same ratio with the same prediluting water as the discharged muds and stirred for 5 minutes.

7.7 Drill cuttings must be stirred and well mixed by hand in their sampling containers prior to testing, using a stainless steel spatula.

8. Procedure

8.1 Ambient receiving water must be used as the "receiving water" in the test. The test container must have an air to liquid interface area of 1000 ± 50 cm^2. The surface of the water should be no more than 5 cm below the top of the test container.

8.2 Plastic liners shall be used, one per container per test, and discarded afterwards. Some liners may inhibit spreading of added oil; operators shall determine an appropriate local source of liners that do not inhibit the spreading of the oil film.

8.3 Drilling fluid materials and deck drainage must be introduced into the test container 1 cm below the water surface, by pipet, at 0.15 mL and 15 mL. Pipets must be filled and discharged with test material prior to the transfer of test material and its introduction into test containers. The test water-test material mixture must be stirred using the pipet to distribute the test material homogenously throughout the test water. The pipet must be used only once for a test and then discarded.

8.4 Drill cuttings and produced sand should be weighed on plastic weighing boats; 1.5 gram and 15 gram samples must be transferred by scraping test material into the test water with a stainless steel spatula. The weighing boat must be immersed in the test water and scraped with the spatula to transfer any residual material to the test container. The test material must be stirred with the spatula to an even distribution of solids on the bottom of the test container.

8.5 Observations must be made no later than 1 hour after the test material is transferred to the test container. Viewing points above the test container should be made from at least three sides of the test container, at viewing angles of approximately 60 deg and 30 deg from the horizontal. Illumination of the test container must be representative of adequate lighting for a working environment to conduct routine laboratory procedures.

8.6 Any detection of a "silvery" or "metallic" sheen, gloss, or increased reflectivity; visual color; or irridescence on the water surface shall constitute a demonstration of "free oil" for the sample. These visual observations include patches, sheets, or streaks of such altered surface characteristics.

APPENDIX B - ANALYSIS OF DIESEL OIL IN DRILLING FLUIDS AND DRILL CUTTINGS (ANALYTICAL PROTOCOL)

1. Scope and Application

This method is to be used as a compliance test for detecting the presence of diesel oil in drilling fluids and drill cuttings waste streams. The method involves the separation of diesel oil from drilling fluid or drill cuttings samples and subsequent qualitative and quantitative analysis by capillary column gas chromatography. The method makes no attempt to chemically identify the individual diesel components but uses a pattern recognition technique for data analysis.

2. Summary of Method

A weighed amount of drilling fluid or drill cuttings is placed in a retort apparatus and distilled according to the retort manufacturer's instructions. The distillate is extracted with methylene chloride, an internal standard is added, and a GC analysis is conducted. Using low attenuation for high sensitivity, a detection of 1 mg/kg of diesel oil in the sample is possible with this method.

The analyst is cautioned that there is no standard diesel oil. The components, as seen by gas chromotography, will differ depending upon the crude source, the date of the diesel oil production and the producer. In addition, there are three basic types of diesel oils: ASTM Designations No. 1-D, No. 2-D, and No. 4-D. The No. 2-D is most commonly referred to in terms of "diesel oil." However, No. 2-D is sometimes blended with No. 1-D which has a lower boiling range. Thus it is highly desirable that the sample chromatograms be matched with a reference standard made from the same diesel oil source suspected to be in the sample.

3. Apparatus, Reagents and Materials

3.1 Apparatus

3.1.1 Gas Chromatograph (GC) - A temperature programmable GC equipped with a flame ionization detector.

3.1.2 Integrator - A recording integrator capable of resolving and integrating capillary peaks.

3.1.3 Chromatographic Column - A borosilicate glass capillary column (WCOT), 30 meter x 0.25 mm ID, coated with Supelco SPB - 1 (Bonded SE-30 methyl silicone) with 1.0 um thickness (Supelco Catalog No. 2-4029). Other columns may be substituted if they can demonstrate similar and satisfactory results.

3.1.4 Distillation Apparatus - A 20 mL retort apparatus (IMCO Services Model No. R2100 or equivalent).

3.1.5 Kuderna - Danish Concentrator - A 500 mL flask, 3 - ball Snyder column and a 10 mL (or 15 mL) receiving ampule graduated in 0.1 ml units at the bottom.

3.1.6 Separatory Funnel - A 60 mL separatory funnel with a Teflon stopcock and glass stopper.

3.1.7 Glass Filtering Funnel - A glass filtering crucible holder (Corning No. 9480 or equivalent).

3.2 Materials and Reagents

3.2.1 Glass Wool - Corning No. 3950 or equivalent.

3.2.2 Anhydrous Sodium Sulfate - Analytical grade.

3.2.3 Methylene Chloride - Nanograde or equivalent.

3.2.4 Trichlorobenzene (TCB) Internal Standard - Dissolve 1.0 gm of 1,3,5 Trichlorobenzene (Kodak No. 1801 or equivalent) in 100 mL of Methylene Chloride. Store in glass and tightly cap with Teflon lid liner to prevent solvent evaporation loss.

4. Procedure

4.1 Sample Preparation

4.1.1 Preweigh or tare the retort sample cup and cap to at least the nearest 0.1 gm. Transfer a well homogenized and representative portion of the material to be tested into the sample cup, filling it to the top. Place the cap on the cup, wipe off the excess material and reweigh. Record the weight of the sample to at least the nearest 0.1 gm.

4.1.2 Following the retort manufacturer's instructions, distill the sample into the unit's glass receiving cylinder. The presence of solids in the distillate will require that the distillation be rerun starting with a new portion of sample. Placing more steel wool in the retort expansion chamber, per manufacturer's instructions, will help prevent the solids from going over in the distillation.

4.1.3 Pour the retort distillate into a 60 mL separatory funnel. Rinse the distillate container with two full portions of methylene chloride into the separatory funnel. Stopper and shake for 1 minute and allow the layers to separate.

4.1.4 Prepare a glass filtering funnel by plugging the bottom with a piece of glass wool and pouring in 1 to 2 inches of anhydrous sodium sulfate. Wet the funnel with a small portion of methylene chloride and allow it to drain to a waste container.

4.1.5 Place the glass filtering funnel into the top of a Kuderna - Danish (K-D) flask equipped with a 10 mL receiving ampule. Drain the methylene chloride (lower) layer into the K-D flask passing it through the glass filtering funnel.

4.1.6 Repeat the methylene chloride extraction twice more, rinsing the retort unit's glass receiving cylinder with two thorough washings each time and draining each methylene chloride extraction into the K-D flask.

4.1.7 Place a Snyder column on the K-D flask and evaporate on a steam bath. Concentrate the sample to a 1.0 mL final volume or until the contents will not concentrate any further and note the final volume. The receiving ampule graduations should be laboratory calibrated for accuracy.

4.2 Gas Chromatography

4.2.1 Using a micropipet, transfer equal portions of the sample from the K-D ampule and the TCB internal standard (a 100 ul portion of each is suggested) into a GC injection vial or other suitable container. Mix thoroughly.

4.2.2 Set up the gas chromatograph conditions as follows:

(a) GC - Injector Port and manifold temperature = 275 C
(b) Column - A SPB-1, 30 meter column with a nitrogen carrier at approximately 2 ml/min, a split ratio of 100:1 and nitrogen make-up (if needed) at 60 mL/min.
(c) Temperature Program - 90 C initial temperature with no hold, 5 C per minute to a final temperature of 250 C; final hold for at least 10 minutes.
(d) Detector - FID with 30 mL/min hydrogen and 240 cc/min air is recommended. Set the amplifier range at 10^{-11} amps full scale (X10 on most instruments)
(e) Recording Integrator - Set the chart speed at a minimum of 1 mL/min. Adjust the attenuation during the run as to exclude minor peaks.

4.2.3 Inject 1 uL of the sample containing the internal standard. The TCB will elute at approximately 8.5 minutes into the run and should be approximately 50 percent at full scale at 8 x 10^{-11}.

4.2.4 Prepare a reference standard using, if possible, the same diesel oil suspected to be in the sample. Using Table 1 as a guide, weigh out the appropriate amount of oil into a tared 10 mL volumetric flask and dilute to volume with methylene chloride. Mix equal portions of the reference oil standard and the TCB as outlined in 4.2.1 and analyze using the same GC conditions used for the analysis of the sample.

TABLE 1

Percent Ranges of Diesel and Standards

Expected % Diesel oil in Sample	Wt of Diesel oil in 10 mL Volumetric* (g)
5	use undiluted oil
3	7.6
1	3.0
.5	1.5

* Weigh oil to the nearest 0.001g

5. Interpretation of Data

5.1 Compare the sample chromatogram to the chromotogram of the standard. If the sample contains diesel oil, the major peaks present in the standard (e.g. those greater than 1 percent of the total integrated area) should also be present in the sample and in the same relative intensity and pattern (See Figure 1).

5.2 Some mineral oil lubricity additives have similar chromatographic patterns to that of diesel oil. The presence of early, smaller peaks from 1 minute (following the solvent peak) to approximately 4 minutes will differentiate between distillates containing only mineral oil and those with diesel oil (See Figure 2).

5.3 The use of the TCB internal standard makes it possible to correlate peaks from sample to standard on the basis of Relative Retention Time (RTT). Approximate RRT's are presented in Table 2.

6. Calculation of Results

6.1 Choose those peaks that are applicable as outlined in Section 5; a minimum of 10 peaks should be used. Sum the integrated areas of the chosen peaks in the sample and divide by the integrated area of the Internal Standard in the sample:

$$\frac{\Sigma A_{ps}}{A_{is}} = RF_s$$

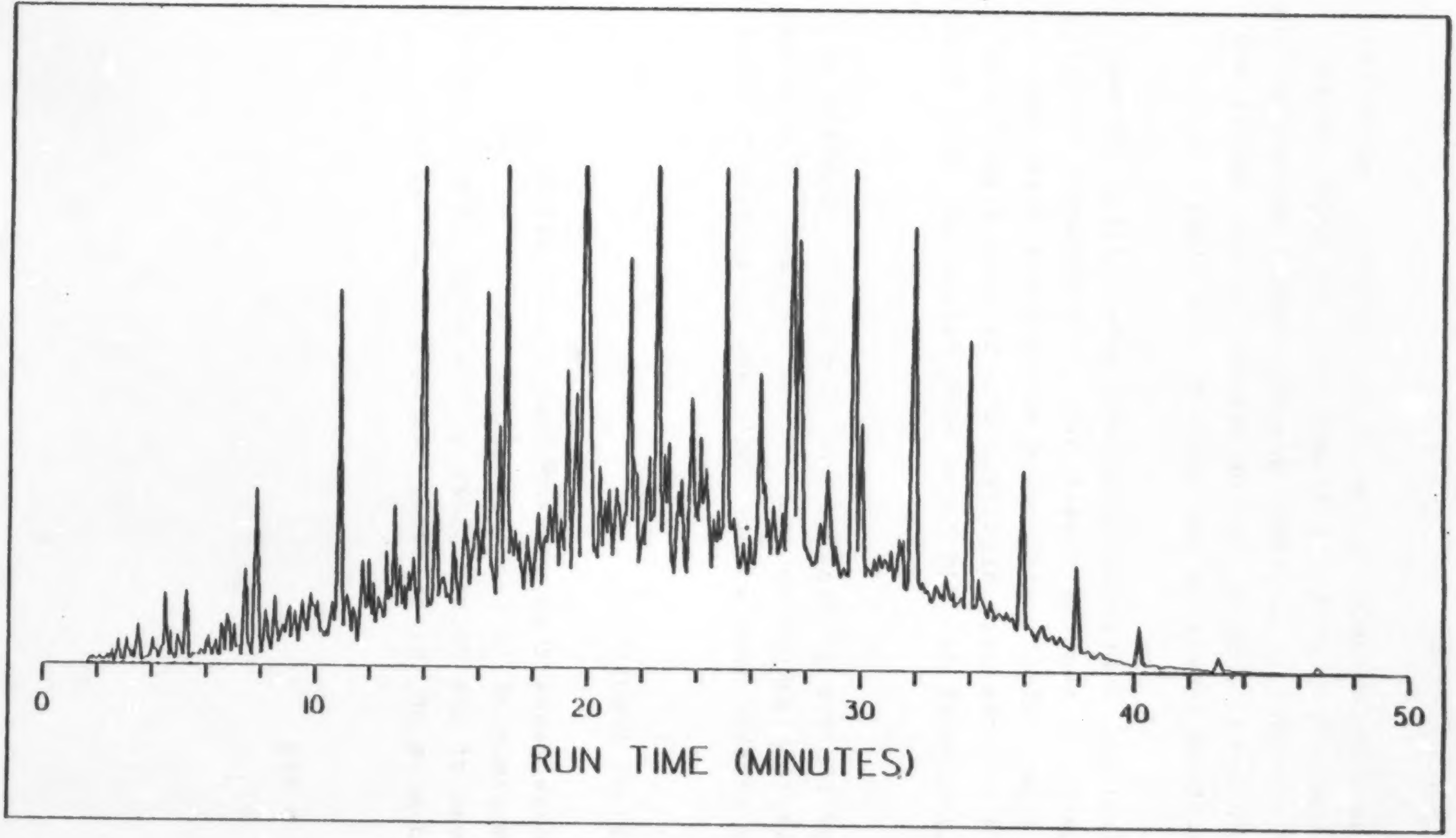


FIGURE I

CHROMATOGRAM OF NO.2 DIESEL OIL SAMPLE

(NO SOLVENT OR INTERNAL STANDARD PEAKS PRESENT)

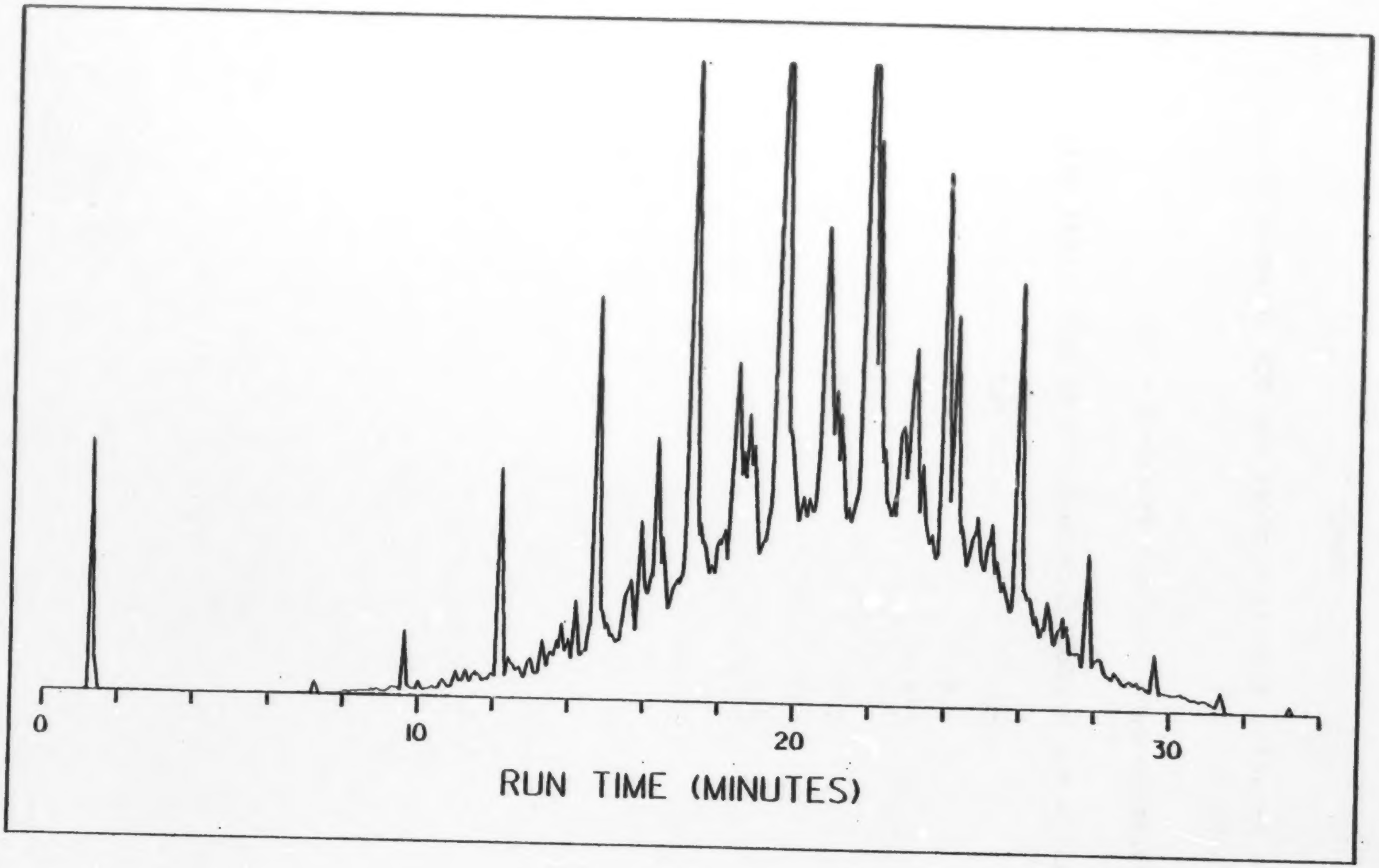


FIGURE 2

CHROMATOGRAM OF MINERAL OIL SAMPLE

TABLE 2

Approximate Relative Retention Times for TCB Internal Standard and No. 2-D Diesel Oil.

1,3,5 Trichlorobenzene Internal Standard = 100

Expected RRT's for Predominate Peaks in No 2-D Diesel Oil:

124
155
179
183
186
188
193
207
216
220
231
245
260
273
276
299
324
348
370

where:

ΣAps = Summation of peak areas of interest in sample
ΣAis = Area of internal standard peak in sample
RFs = Response factor for sample

6.2 Repeat the above process (6.1) for the chosen peaks in the standard:

$$\frac{\Sigma Apr}{Air} = RFr$$

where:

ΣApr = Summation of peak areas of interest in reference standard
Air = Area of internal standard peak in the reference standard
RFr = Response factor for reference standard

6.3 Calculate the mg/kg of diesel oil in the sample as follows:

$$\text{mg/kg Diesel Oil} = \frac{RFs \times Vs \times Cr \times 1000}{RFr \times Gs}$$

where:

RFs = Response factor for sample
RFr = Response factor for reference standard
Vs = Final volume of sample from K-D in mL
Cr = Concentration of reference standard in mg/mL
Gs = Starting weight of sample in grams on a wet weight or whole mud basis.

Note: This equation does not take into account attenuation changes if they affect the calculated peak areas as reported by the integrator.

7. Quality Control

7.1 Each laboratory that uses this method is required to operate a formal quality control program. The minimum requirements of this program consist of an initial demonstration of laboratory capability, the analysis of a retorted diesel oil standard as a continuing check on recovery, and duplicate samples for a precision check on performance. The laboratory is required to maintain performance records to define the quality of data that are generated. Ongoing performance checks must be compared with established performance criteria to determine if the results of analyses are within accuracy and precision limits expected of the method.

7.2 In order to demonstrate recovery , a diesel oil standard must be subjected to the entire analytical procedure starting with Section 4.1. Pipette 1.00 ml of the reference diesel oil into the preweighed or tared retort sample cup and weigh to the nearest 0.001 gram. Place a small plug of steel wool into the cup, cap and proceed with the retort distillation. Calculate the percent recovery of the retorted reference standard to that of a reference standard prepared as specified in Section 4.2.4. The percent recovery of the retorted reference standard must fall within 80 to 120 percent recovery. This should be performed on each retort unit utilized before attempting any sample analyses. Reference standards should be subjected to the entire analytical procedure starting with Section 4.1 at least once for each batch of samples processed or for every ten samples analyzed.

7.3 The laboratory must analyze duplicate samples for each sample type at a minimum of 20 percent. A duplicate sample shall consist of a well-mixed, representative aliquot of the sample and should be subjected to the entire analytical procedure starting with Section 4.1. The relative percent differences (RPD) for duplicates are calculated as follows:

$$RPD = \frac{(D1 - D2)}{(D1 + D2)/2} \times 100$$

where:

RPD = relative percent difference
D1 = percent of diesel oil in the first sample
D2 = percent diesel oil in the second sample (duplicate)

A control limit of ± 20 percent for RPD shall be used.

APPENDIX C - DRILLING FLUIDS TOXICITY TEST

I. SAMPLE COLLECTION

The collection and preservation methods for drilling fluids (muds) and water samples presented here are designed to minimize sample contamination and alteration of the physical or chemical properties of the samples due to freezing, air oxidation, or drying.

1-A. Apparatus

(1) The following items are required for water and drilling mud sampling and storage:

a. Acid-rinsed linear-polyethylene bottles or other appropriate noncontaminating drilling mud sampler.

b. Acid-rinsed linear-polyethylene bottles or other appropriate noncontaminating water sampler.

c. Acid-rinsed linear-polyethylene bottles or other appropriate noncontaminated vessels for water and mud samples.

d. Ice chests for preservation and shipping of mud and water samples.

1-B. Water Sampling

(1) Collection of water samples shall be made with appropriate acid-rinsed linear-polyethylene bottles or other appropriate noncontaminating water sampling devices. Special care shall be taken

to avoid the introduction of contaminants from the sampling devices and containers. Prior to use, the sampling devices and containers should be thoroughly cleaned with a detergent solution, rinsed with tap water, soaked in 10 percent hydrochloric acid (HCl) for 4 hours, and then thoroughly rinsed with glass-distilled water.

1-C. Drilling Mud Sampling

(1) Drilling mud formulations to be tested shall be collected from active field systems. Obtain a well-mixed sample from beneath the shale shaker after the mud has passed through the screens. Samples shall be stored in polyethylene containers or in other appropriate uncontaminated vessels. Prior to sealing the sample containers on the platform, flush as much air out of the container by filling it with drilling fluid sample, leaving a one inch space at the top.

(2) Mud samples shall be immediately shipped to the testing facility on blue or wet ice (do not use dry ice) and continuously maintained at 0-4°C until the time of testing.

(3) Bulk mud samples shall be thoroughly mixed in the laboratory using a 1000 rpm high shear mixer and then subdivided into individual, small wide-mouthed (e.g., one or two liter) non-contaminating containers for storage.

(4) The drilling muds stored in the laboratory shall have any excess air removed by flushing the storage containers with nitrogen under pressure anytime the containers are opened. Moreover, the sample in any container opened for testing must be thoroughly stirred using a 1000 rpm high shear mixer prior to use.

(5) Most drilling mud samples may be stored for periods of time longer than 2 weeks prior to toxicity testing provided that proper containers are used and proper conditions are maintained.

II. SUSPENDED PARTICULATE PHASE SAMPLE PREPARATION

(1) Mud samples that have been stored under specified conditions in this protocol shall be prepared for tests within three months after collection. The SPP shall be prepared as detailed below.

2-A. Apparatus

(1) The following items are required:

a. Magnetic stir plates and bars.
b. Several graduated cylinders, ranging in volume from 10 mL to 16
c. Large (15 cm) powder funnels.
d. Several 2-liter graduated cylinders.
e. Several 2-liter large mouth graduated Erlenmeyer flasks.

(2) Prior to use, all glassware shall be thoroughly cleaned. Wash all glassware with detergent, rinse five times with tap water, rinse once with acetone, rinse several times with distilled or deionized water, place in a clean 10-percent (or stronger) HCl acid bath for a minimum of 4 hours, rinse five times with tap water, and then rinse five times with distilled or deionized water. For test samples containing mineral oil or diesel oil, glassware should be washed with petroleum ether to assure removal of all residual oil. NOTE: If the glassware with nytex cups soaks in the acid solution longer than 24 hours, then an equally long deionized water soak should be performed.

2-B. Test Seawater Sample Preparation

(1) Diluent seawater and exposure seawater samples are prepared by filtration through a 1.0 micrometer filter prior to analysis.

(2) Artificial seawater may be used as long as the seawater has been prepared by standard methods or PSTM methods, has been properly "seasoned," filtered, and has been diluted with distilled water to the same specified 20 ± 2 ppt salinity and 20 ± 2°C temperature as the "natural" seawater.

2-C. Sample Preparation

(1) The pH of the mud shall be tested prior to its use. If the pH is less than 9, if black spots have appeared on the walls of the sample container, or if the mud sample has a foul odor, that sample shall be discarded. Subsample a manageable aliquot of mud from the well-mixed original sample. Mix the mud and filtered test seawater in a volumetric mud-to-water ratio of 1 to 9. This is best done by the method of volumetric displacement in a 2-L, large mouth, graduated Erlenmeyer flask. Place 1000 ml of dilute seawater into the graduated Erlenmeyer flask. The mud subsample is then carefully added via a powder funnel to obtain a total volume of 1200 ml. (A 200 mL volume of mud will now be in the flask).

The 2-L, large mouth, graduated Erlenmeyer flask is then filled to the 2000 mL mark with 800 mL of seawater, which produces a slurry with a final ratio of one volume drilling mud to nine volumes water. If the volume of SPP required for testing or analysis exceeds 1500 to 1600 mL, the initial volumes should be proportionately increased. Alternatively, several 2-L drill mud/water slurries may be prepared as outlined above and combined to provide sufficient SPP.

(2) Mix this mud/water slurry with magnetic stirrers for 5 minutes. Measure the pH and, if necessary, adjust (decrease) the pH of the slurry to within 0.2 units of the seawater by adding 6N HCl while stirring the slurry. Then, allow the slurry to settle for 1 hour. Record the amount of HCl added.

(3) At the end of the settling period, carefully decant (do not siphon) the Suspended Particulate Phase (SPP) into an appropriate container. Decanting the SPP is one continuous action. In some cases no clear interface will be present; that is, there will be no solid phase that has settled to the bottom. For those samples the entire SPP solution should be used when preparing test concentrations. However, in those cases when no clear interface is present, the sample must be remixed for five minutes. This insures the homogeneity of the mixture prior to the preparation of the test concentrations. In other cases, there will be samples with two or more phases, including a solid phase. For those samples, carefully and continuously decant the supernatant until the solid phase on the bottom of the flask is reached. The decanted solution is defined to be 100 percent SPP. Any other concentration of SPP refers to a percentage of SPP that is obtained by volumetrically mixing 100 percent SPP with seawater.

(4) SPP samples to be used in toxicity tests shall be mixed for 5 minutes and must not be preserved or stored.

(5) Measure the filterable and unfilterable residue of each SPP prepared for testing. Measure the dissolved oxygen (DO) and pH of the SPP. If the DO is less than 4.9 ppm, aerate the SPP to at

least 4.9 ppm which is 65 percent of saturation. Maximum allowable aeration time is 5 minutes using a generic commercial air pump and air stone. Neutralize the pH of the SPP to a pH 7.8 ±.1 using a dilute HCl solution. If too much acid is added to lower the pH saturated NaOH may be used to raise the pH to 7.8 ±.1 units. Record the amount of acid or NaOH needed to lower/ raise to the appropriate pH. Three repeated DO and pH measurements are needed to insure homogeneity and stability of the SPP. Preparation of test concentrations may begin after this step is complete.

(6) Add the appropriate volume of 100 percent SPP to the appropriate volume of seawater to obtain the desired SPP concentration. The control is seawater only. Mix all concentrations and the control for 5 minutes by using magnetic stirrers. Record the time; and, measure DO and pH for Day 0. Then, the animals shall be randomly selected and placed in the dishes in order to begin the 96-hour toxicity test.

III. GUIDANCE FOR PERFORMING SUSPENDED PARTICULATE PHASE TOXICITY TESTS USING Mysidopsis bahia.

3-A. Apparatus

(1) Items listed by Borthwick [267] are required for each test series, which consists of one set of control and test containers, with three replicates of each.

3-B. Sample Collection Preservation

(1) Drilling muds and water samples are collected and stored, and the suspended particulate phase prepared as described in Section 1-C.

3-C. Species Selection

(1) The Suspended Particulate Phase (SPP) tests on drilling muds shall utilize the test species *Mysidopsis bahia*. Test animals shall be 3 to 6 days old on the first day of exposure. Whatever the source of the animals, collection and handling should be as gentle as possible. Transportation to the laboratory should be in well-aerated water from the animal culture site at the temperature and salinity from which they were cultured. Methods for handling, acclimating, and sizing bioassay organisms given by Borthwick [267] and Nimmo [268] shall be followed in matters for which no guidance is given here.

3.D. Experimental Conditions

(1) Suspended particulate phase (SPP) tests should be conducted at a salinity of 20 ± 2 ppt. Experimental temperature should be 20 ± 2°C. Dissolved oxygen in the SPP shall be raised to or maintained above 65 percent of saturation prior to preparation of the test concentrations. Under these conditions of temperature and salinity, 65 percent saturation is a DO of 5.3ppm. Beginning at Day 0- before the animals are placed in the text containers DO, temperature, salinity, and pH shall be measured every 24 hours. DO should be reported in milligrams per liter.

(2) Aeration of test media is required during the entire test with a rate estimated to be 50-140 cubic centimeters/minute.

This air flow to each test dish may be achieved through polyethylene tubing (0.045-inch inner diameter and 0.062-inch outer diameter) by a small generic aquarium pump. The delivery method, surface area of the aeration stone, and flow characteristics shall be documented. All treatments, including control, shall be the same.

(3) Light intensity shall be 1200 microwatts/cm^2 using cool white fluorescent bulbs with a 14-hr light and 10-hr dark cycle. This light/dark cycle shall also be maintained during the acclimation period and the test.

3-E. Experimental Procedure

(1) Wash all glassware with detergent, rinse five times with tap water, rinse once with acetone, rinse several times with distilled or deionized water, place in a clean 10 percent HCl acid bath for a minimum of 4 hours, rinse five times with tap water, and then rinse five times with distilled water.

(2) Establish the definitive test concentration based on results of a range finding test. A minimum of five test concentrations plus a negative and positive (reference toxicant) control is required for the definitive test. To estimate the LC-50, two concentrations shall be chosen that give (other than zero and 100 percent) mortality above and below 50 percent.

(3). Twenty organisms are exposed in each test dish. Nytex® cups shall be inserted into every test dish prior to adding the animals. These "nylon mesh screen" nytex holding cups are fabricated by gluing a collar of 363-micrometer mesh nylon screen to a 15-centimerer wide Petri dish with silicone sealant. The nylon screen collar is approximately 5 centimerers high. The animals are then placed into the test concentration within the confines of the Nytex® cups.

(4) Individual organisms shall be randomly assigned to treatments. A randomization procedure is presented in Section V of this protocol. Make every attempt to expose animals of approximately equal size. The technique described by Borthwick [267], or other suitable substitutes, should be used for transferring specimens. Throughout the test period, mysids shall be fed daily with approximately 50 Artemia (brine shrimp) nauplii per mysid. This will reduce stress and decrease cannibalism.

(5) Cover the dishes, aerate, and incubate the test containers in an appropriate test chamber. Positioning of the test containers holding various concentrations of test solution should be randomized if incubator arrangement indicates potential position difference. The test medium is not replaced during the 96-hour test.

(6) Observations may be attempted at 4, 6 and 8 hours; they must be attempted at 0, 24, 48, and 72 hours and must be made at 96 hours. Attempts at observations refers to placing a test dish on a light table and visually count the animals. Do not lift the "nylon mesh screen" cup out of the test dish to make the observation. No unnecessary handling of the animals should occur during the 96 hour test period. DO and pH measurements must also be made at 0, 24, 48, 72, and 96 hours. Take and replace the test medium necessary for the DO and pH measurements outside of the nytex cups to minimize stresses on the animals.

(7) At the end of 96 hours, all live animals must be counted. Death is the end point, so the number of living organisms is

recorded. Death is determined by lack of spontaneous movement. All crustaceans molt at regular intervals, shedding a complete exoskeleton. Care should be taken not to count an exoskeleton. Dead animals might decompose or be eaten between observations. Therefore, always count living, not dead animals. If daily observations are made, remove dead organisms and molted exoskeletons with a pipette or forceps. Care must be taken not to disturb living organisms and to minimize the amount of liquid withdrawn.

IV. METHODS FOR POSITIVE CONTROL TESTS (REFERENCE TOXICANT)

(1) Sodium lauryl sulfate (dodecyl sodium sulfate) is used as a reference toxicant for the positive control. The chemical used should be approximately 95 percent pure. The source, lot number, and percent purity shall be reported.

(2) Test methods are those used for the drilling fluid tests, except that the test material was prepared by weighing one gram sodium lauryl sulfate on an analytical balance, adding the chemical to a 100-milliliter volumetric flask, and bringing the flask to volume with deionized water. After mixing this stock solution, the test mixtures are prepared by adding 0.1 milliliter of the stock solution for each part per million desired to one liter of seawater.

(3) The mixtures are stirred briefly, water quality is measured, animals are added to holding cups, and the test begins. Incubation and monitoring procedures are the same as those for the drilling fluids.

V. RANDOMIZATION PROCEDURE

(1) The purpose of this procedure is to assure that mysids are impartially selected and randomly assigned to six test treatments (five drilling fluid or reference toxicant concentrations and a control) and impartially counted at the end of the 96-hour test. Thus, each test setup, as specified in the randomization procedure, consists of 3 replicates of 20 animals for each of the six treatments, i.e., 360 animals per test. Figure 1 is a flow diagram that depicts the procedure schematically and should be reviewed to understand the over-all operation. The following tasks shall be performed in the order listed.

(2) Mysids are cultured in the laboratory in appropriate units. If mysids are purchased, go to Task 3.

(3) Remove mysids from culture tanks (6, 5, 4, and 3 days before the test will begin, i.e. Tuesday, Wednesday, Thursday, and Friday if the test will begin on Monday) and place them in suitably large maintenance containers so that they can swim about freely and be fed.

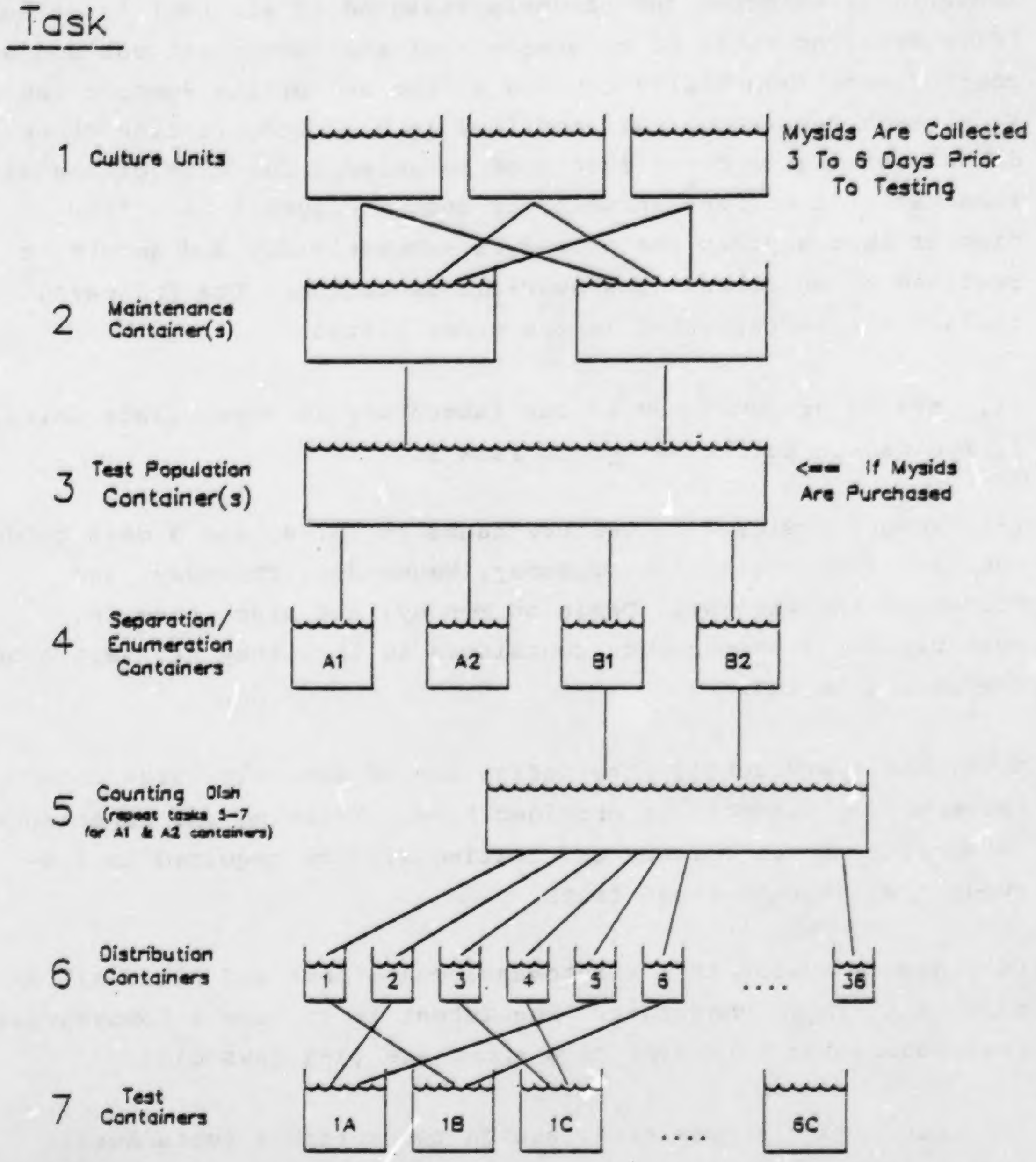
NOTE: Not every detail (the definition of suitably large containers, for example) is provided here. Training and experience in aquatic animal culture and testing will be required to successfully complete these tests.

(4) Remove mysids from maintenance containers and place all animals in a single container. The intent is to have a homogeneous test population of mysids of a known age (3-6 days old).

(5) For each toxicity test, assign two suitable containers (500-milliliter (mL) beakers are recommended) for mysid

Figure 1

Mysid Randomization Procedure


Task
1 Culture Units
Mysids Are Collected 3 To 6 Days Prior To Testing
2 Maintenance Container(s)
3 Test Population Container(s)
<== If Mysids Are Purchased
4 Separation/ Enumeration Containers
A1
A2
B1
B2
5 Counting Dish (repeat tasks 5-7 for A1 & A2 containers)
6 Distribution Containers
1
2
3
4
5
6
....
36
7 Test Containers
1A
1B
1C
....
6C

separation/enumeration. Label each container (A1, A2, B1, B2, and C1, C2, for example, if two drilling fluid tests and a reference toxicant test are to be set up on one day). The purpose of this task is to allow the investigator to obtain a close estimate of the number of animals available for testing and to prevent unnecessary crowding of the mysids while they are being counted and assigned to test containers. Transfer the mysids from the large test population container to the labeled separation and enumeration containers but do not place more than 200 mysids in a 500-mL beaker. Be impartial in transferring the mysids; place approximately equal numbers of animals (10-15 mysids is convenient) in each container in a cyclic manner rather than placing the maximum number in each container at one time.

Note: It is important that the animals not be unduly stressed during this selection and assignment procedure. Therefore, it will probably be necessary to place all animals (except the batch immediately being assigned to test containers) in mesh cups with flowing seawater or in larger volume containers with aeration. The idea is to provide the animals with near optimal conditions to avoid additional stress.

(6) Place the mysids from the two labeled enumeration containers assigned to a specific test into one or more suitable containers to be used as counting dishes (2liter Carolina dishes are suggested). Because of the time required to separate, count, and assign mysids, two or more people may be involved in completing this task. If this is done, two or more counting dishes may be used, but the investigator must make sure that approximately equal numbers of mysids from each labeled container are placed in each counting dish.

(7) By using a large-bore, smooth-tip glass pipette, select mysids from the counting dish(es) and place them in the 36 individually numbered distribution containers (10-ml beakers are suggested). The mysids are assigned two at a time to the 36 containers by using a randomization schedule similar to the one presented below. At the end of selection/assignment round 1, each container will contain two mysids; at the end of round 2, they will contain four mysids; and so on until each contains ten mysids.

Example of a Randomization Schedule

Selection/Assignment Round (2 mysids each)	Place mysid in the numbered distribution containers in the random order shown
1	8, 21, 6, 28, 33, 32, 1, 3, 10, 9, 4, 14, 23, 2, 34, 22, 36, 27, 5, 30, 35, 24, 12, 25, 11, 17, 19, 26, 31, 7, 20, 15, 18, 13, 16, 29
2	35, 18, 5, 12, 32, 34, 22, 3, 9, 16, 26, 13, 20, 28, 6, 21, 24, 30, 8, 31, 7, 23, 2, 15, 25, 17, 1, 11, 27, 4, 19, 36, 10, 33, 14, 29
3	7, 19, 14, 11, 34, 21, 25, 27, 17, 18, 6, 16, 29, 2, 32, 10, 4, 20, 3, 9, 1, 5, 28, 24, 31, 15, 22, 13, 33, 26, 36, 12, 8, 30, 35, 23

4	30, 2, 18, 5, 8, 27, 10, 25, 4, 20, 26, 15, 31, 36, 35, 23, 11, 29, 16, 17, 28, 1, 33, 14, 9, 34, 7, 3, 12, 22, 21, 6, 19, 24, 32, 13
5	34, 28, 16, 17, 10, 12, 1, 36, 20, 18, 15, 22, 2, 4, 19, 23, 27, 29, 25, 21, 30, 3, 9, 33, 32, 6, 14, 11, 35, 24, 26, 7, 31, 5, 13, 8

(8) Transfer mysids from the 36 distribution containers to 18 labeled test containers in random order. A label is assigned to each of the three replicates (A, B, C) of the six test concentrations. Count and record the 96 hour response in a impartial order.

(9) Repeat tasks 5-7 for each toxicity test. A new random schedule should be followed in Tasks 6 and 7 for each test.

NOTE: If a partial toxicity test is conducted, the procedures described above are appropriate and should be used to prepare the single test concentration and control, along with the reference toxicant test.

5-B. Data Analysis and Interpretation

(1) Complete survival data in all test containers at each observation time shall be presented in tabular form. If greater than 10 percent mortality occurs in the controls, all data shall be discarded and the experiment repeated. Unacceptably high control mortality indicates the presence of important stresses on the

organisms other than the material being tested, such as injury or disease, stressful physical or chemical conditions in the containers, or improper handling, acclimation, or feeding. If 10 percent mortality or less occurs in the controls, the data may be evaluated and reported.

(2) A definitive, full bioassay conducted according to the EPA protocol is used to estimate the concentration that is lethal to 50 percent of the test organisms that do not die naturally. This toxicity measure is known as the median lethal concentration, or LC-50. The LC-50 is adjusted for natural mortality or natural responsiveness. The maximum likelihood estimation procedure with the adjustments for natural responsiveness as given by D. J. Finney, in Probit Analysis 3rd edition, 1971, Cambridge University Press, Chapter 7, can be used to obtain the probit model estimate of the LC 50 and the 95 percent fiducial (confidence) limits for the LC-50. These estimates are obtained using the logarithmic transform of the concentration. The heterogeneity factor (Finney 1971, pages 70-72) is not used. For a test material to pass the toxicity test, according to the requirements stated in the offshore oil and gas extraction industry BAT regulation, the lower 95 percent limit for the LC-50 adjusted for natural responsiveness must be greater than 3 percent suspended particulate phase (SPP) concentration by volume unadjusted for the 1 to 9 dilution. Other toxicity test models may be used to obtain toxicity estimates provided the modeled mathematical expression for the lethality rate must increase continuously with concentration. The lethality rate is modeled to increase with concentration to reflect an assumed increase in toxicity with concentration even though the observed lethality may not increase uniformly because of unpredictable animal response fluctuations.

(3) The range finding test is used to establish a reasonable set of test concentrations in order to run the definitive test.However, if the lethality rate changes rapidly over a narrow range of concentrations, the range finding assay may be too coarse to establish an adequate set of test concentrations for a definitive test.

(4) The EPA Environmental Research Laboratory in Gulf Breeze, Florida prepared a Research and Development Report titled Acute Toxicity of Eight Drilling Fluids to Mysid Shrimp (*Mysidopsis bahia*), May 1984 EPA-600/3-84-067. The Gulf Breeze data for drilling fluid number 1 are displayed in Table 1 for purposes of an example of the probit analysis described above. The SAS Probit Procedure (SAS Institute, Statistical Analysis System, Cary, North Carolina, 1982) was used to analyze these data. The 96-hour LC50 adjusted for the estimated spontaneous mortality rate is 3.3 percent SPP with 95 percent limits of 3.0 and 3.5 percent SPP with the 1 to 9 dilution. The estimated spontaneous mortality rate based on all of the data is 9.6 percent.

TABLE 1

LISTING OF ACUTE TOXICITY TEST DATA (8/83-9/83) WITH EIGHT GENERIC DRILLING FLUIDS AND MYSID SHRIMP

FLUID N2=1

Percent Concentration	Number Exposed	Number Dead (96 Hours)	Number Alive (96 Hours)
0	60	3	57
1	60	11	49
2	60	11	49
3	60	25	35
4	60	48	12
5	60	60	0

5-C. The Partial Toxicity Test for Evaluation of Test Material

(1) A partial test conducted according to EPA protocol can be used economically to demonstrate that a test matrial passes the toxicity test. the partial test cannot be used to estimate the LC-50 adjusted for natural response.

(2) To conduct a partial test follow the test protocol for preparation of the test material and organisms. Prepare the control (zero concentration), one test concentration (3 percent suspended particulate phase) and the reference toxicant according to the methods of the full test. A range finding test is not used for the partial test.

(3) Sixty test organisms are used for each test concentration. Find the number of test organisms killed in the control (zero percent SPP) concentration in the column labeled X0 of Table 2. If the number of organisms in the control (zero percent SPP) exceeds the table values, then the test is unacceptable and must be repeated. If the number of organisms killed in the 3 percent test concentration is less than or equal to corresponding number in the column labeled X1 then the test material passes the partial toxicity test. Otherwise the test material fails the toxicity test.

(4) Data shall be reported as percent suspended particulate phase.

TABLE 2

X0	X1
--	--
0	22
1	22
2	23
3	23
4	24
5	24
6	25

6. References

267. Borthwick, Patrick W. 1978. Methods for acute static toxicity tests with mysid shrimp (*Mysidopsis bahia*). *Bioassay Procedures for the Ocean Disposal Permit Program*, EPA-600/9 78-010: March.

268. Nimmo, D.R., T. L. Hamaker, and C. A. Somers. 1978. Culturing the mysid (*Mysidopsis bahia*) in flowing sea water or a static system. *Bioassay Procedures for the Ocean Disposal Permit Program*, EPA-600/9-78-010: March.

269. American Public Health Association et al. 1980. *Standard Methods for the Examination of Water and Wastewater*. Washington, D.C. 15th Edition: 90-99.

APPENDIX D - 126 PRIORITY POLLUTANTS

Acenaphthene
Acrolein
Acrylonitrile
Benzene
Benzidine
Carbon tetrachloride (tetrachloromethane)
Chlorobenzene
1,2,4-trichlorobenzene
Hexachlorobenzene
1,2-dichloroethane
1,1,1-trichloroethane
Hexachloroethane
1,1-dichloroethane
1,1,2-trichloroethane
1,1,2,2-tetrachloroethane
Chloroethane
Bis(2-chloroethyl) ether
2-chloroethyl vinyl ether (mixed)
2-chloronaphthalene
2,4,6-trichlorophenol
Parachlorometa cresol
Chloroform (trichloromethane)
2-chlorophenol
1,2-dichlorobenzene
1,3-dichlorobenzene
1,4-dichlorobenzene
3,3-dichlorobenzidine
1,1-dichloroethylene
1,2-trans-dichloroethylene
2,4-dichlorophenol
1,2-dichloropropane

1,2-dichloropropylene (1,3-dichloropropene)
2,4-dimethylphenol
2,4-dinitrotoluene
2,6-dinitrotoluene
1,2-diphenylhydrazine
Ethylbenzene
Fluoranthene
4-chlorophenyl phenyl ether
4-bromophenyl phenyl ether
Bis(2-chloroisopropyl)ether
Bis(2-chloroethoxy) methane
Methylene chloride(dichloromethane)
Methyl chloride (dichloromethane)
Methyl bromide (bromomethane)
Bromoform (tribromomethane)
Dichlorobromomethane
Chlorodibromomethane
Hexachlorobutadiene
Hexachlorocyclopentadiene
Isophorone
Naphthalene
Nitrobenzene
2-nitrophenol
4-nitrophenol
2,4-dinitrophenol
4,6-dinitro-o-cresol
N-nitrosodimethylamine
N-nitrosodiphenylamine
N-nitrosodi-n-propylamine
Pentachlorophenol
Phenol
Bis(2-ethylhexyl)phthalate

Butyl benzyl phthalate
Di-N-Butyl Phthalate
Di-n-Octyl phthalate
Diethyl Phthalate
Dimethyl phthalate
1,2-benzanthracene (benzo(a)anthracene)
Benzo(a)pyrene (3,4-benzo-pyrene)
3,4-Benzofluoranthene(benzo(b)fluoranthene)
11,12-benzofluoranthene(benzo(b)fluoranthene)
Chrysene
Acenapthylene
Anthracene
1,12-benzoperylene(benzo(ghi)perylene)
Fluorene
Phenanthrene
1,2,5,6-dibenzanthracene(dibenzo(h)anthracene)
Indeno(1,2,3-cd)pyrene(2,3-o-phenylene pyrene)
Pyrene
Tetrachloroethylene
Toluene
Trichloroethylene
Vinyl chloride (chloroethylene)
Aldrin
Dieldrin
Chlordane (technical mixture and metabolites)
4,4-DDT
4,4-DDE(p,p-DDX)
4,4-DDD(p,p-TDE)
Alpha-endosulfan
Beta-endosulfan
Endosulfan sulfate
Endrin

Endrin aldehyde
Heptachlor
Heptachlor epoxide(BHC-hexachlorocyclohexane)
Alpha-BHC
Beta-BHC
Gamma-BHC(lindane)
Delta-BHC(PCB-polychlorinated biphenyls)
PCB-1242(Arochlor 1242)
PCB-1254(Arochlor 1254)
PCB-1221(Arochlor 1221)
PCB-1232(Arochlor 1232)
PCB-1248(Arochlor 1248)
PCB-1260(Arochlor 1260)
PCB-1016(Arochlor 1016)
Toxaphene
Antimony
Arsenic
Asbestos
Beryllium
Cadmium
Chromium
Copper
Cyanide, Total
Lead
Mercury
Nickel
Selenium
Silver
Thallium
Zinc
2,3,7,8-tetrachloro-dibenzo-p-dioxin (TCDD)

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